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Supreme Court of the United States

October Term, 1996

ASSOCIATED GAS DISTRIBUTORS, *et al.*,

Petitioners,

vs.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

AND RELATED PETITIONS

Petition for a Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

APPENDIX TO PETITION FOR A WRIT OF CERTIORARI

Volume II, pp. 408a - End

FREDERICK MORING*
CLIFTON S. ELGARTEN
CROWELL & MORING LLP
1001 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2595
(202) 624-2500

Attorneys for Petitioner Associated Gas Distributors

JOHN E. HOLTZINGER, JR.
KEVIN M. DOWNEY
LONG, ALDRIDGE & NORMAN
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004
(202) 624-1255

Attorneys for Petitioners Atlanta Gas Light Company and Chattanooga Gas Company

(Additional Petitioners' Counsel Listed on Following Two Pages)

January 27, 1997

* *Counsel of Record*

70391
(800) 3 APPEAL • (800) 5 APPEAL • (800) BRIEF 21
Lutz Appellate Services, inc.

ROY R. ROBERTSON, JR.
DEFREES & FISKE
200 South Michigan Avenue
Chicago, Illinois 60604
(312) 372-4000

Attorneys for Petitioner
Northern Indiana Public Service Company

STEVEN M. SHERMAN*
135 North Pennsylvania Street
Suite 800
Indianapolis, Indiana 46204
(317) 231-6824

Of Counsel:
JOHN F. PRITCHARD
MARY ANN WALKER
NEIL L. LEVY
DAVID A. CRICHLOW
WINTHROP, STIMSON, PUTNAM & ROBERTS
1133 Connecticut Avenue, N.W.
Washington, D.C. 20036
(202) 775-9816

Attorneys for Petitioner
Citizens Gas & Coke Utility

WILLIAM T. MILLER
JOHN P. GREGG
MILLER, BALIS & O'NEIL, P.C.
1140 19th Street, N.W.
Suite 700
Washington, D.C. 20036
(202) 296-2960

Attorneys for Petitioner
American Public Gas Association

(Additional Petitioners' Counsel Continued on Following Page)

* *Counsel of Record*

RICHARD M. BLUMBERG
Associate General Counsel
Burlington Resources Oil & Gas Company
5051 Westheimer
Suite 1400
Houston, Texas 77056
(281) 878-3700

KIM M. CLARK*
JOHN, HENGERER & ESPOSITO
1200 17th Street, N.W.
Suite 600
Washington, D.C. 20036
(202) 429-8800

Attorneys for Petitioner
Burlington Resources Oil & Gas Company

DENNIS LANE*
DAVID D'ALESSANDRO
MORRISON & HECKER L.L.P.
1150 18th Street, N.W.
Suite 800
Washington, D.C. 20036-3816
(202) 785-9100

MAUREEN O. HELMER
General Counsel
LARRY MALONE
Public Service Commission
of the State of New York
Three Empire State Plaza
Albany, New York 12223

Attorneys for Petitioners
Public Service Commission
of the State of New York, et al.,

* *Counsel of Record*

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Martin L. Allday, Chairman; Charles A Trabandt, Elizabeth Anne Moler, Jerry J. Langdon and Branko Terzic.

Docket No. RM91-11-002

PIPELINE SERVICE OBLIGATIONS AND REVISIONS TO REGULATIONS GOVERNING SELF-IMPLEMENTING TRANSPORTATION UNDER PART 284 OF THE COMMISSION'S REGULATIONS

Docket No. RM87-34-068

REGULATION OF NATURAL GAS PIPELINES AFTER PARTIAL WELLHEAD DECONTROL

ORDER NO. 636-A

ORDER DENYING REHEARING IN PART, GRANTING REHEARING IN PART, AND CLARIFYING ORDER NO. 636

(Issued August 3, 1992)

Appendix C

I. INTRODUCTION

On April 8, 1992, the Federal Energy Regulatory Commission issued Order No. 636.[1] It requires significant structural changes in the services provided by natural gas pipelines. As discussed below, this order largely denies rehearing,[2] but grants rehearing in part to make a number of adjustments to Order No. 636 and clarifies Order No. 636.

II. SUMMARY OF ORDER NO. 636 AND MAIN CHANGES IN THIS ORDER

In Order No. 636, the Commission set forth in detail its goals in, and reasons for, restructuring the regulation of interstate natural gas pipeline services. In brief, the Commission found that the pre-Order No. 636 regulatory structure of the pipeline industry has, and will continue to have, a harmful impact on all segments of the natural gas industry and on the Nation. The Commission concluded that it was appropriate to take remedial action to improve the competitive structure of the natural gas industry to further the creation of an efficient national wellhead market for gas without adversely affecting the quality and reliability of the service provided by pipelines to their customers. The Commission believes that its action will result in a modern, viable natural gas industry specifically fashioned to the needs

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1. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, 57 FR 13267 (April 16, 1992), III FERC Stats & Regs. ¶ 30,939 (1992).

2. See the appendix for a list of the parties seeking rehearing or clarification or both.

of all gas consumers and the Nation for an adequate and reliable supply of clean and abundant natural gas at reasonable prices.

In brief, the salient aspects of Order No. 636 are as follows:

- Pipelines must unbundle (*i.e.*, separate) their sales and transportation services.

- Pipelines must provide access to storage on an open access contract basis.

- Pipelines must provide open access transportation services that are equal in quality for all gas supplies, whether purchased from the pipeline or elsewhere.

- Pipelines that provided a firm sales service on May 18, 1992, must offer a no-notice firm transportation service under which firm shippers may receive delivery of gas on demand up to their firm entitlements without incurring daily balancing and scheduling penalties.

- Pipelines must provide all shippers with equal and timely access to information relevant to the availability of their open access transportation services. The information must be provided through the use of an electronic bulletin board.

- Pipelines may not include in their tariffs any provision that inhibits the development of market centers.

Appendix C

- Open access pipelines must allow firm transportation customers of downstream pipelines to acquire capacity on upstream pipelines held by downstream pipelines.

- Pipelines must implement a capacity releasing program so that firm shippers can release unwanted capacity to those desiring capacity.

- Pipeline transportation rates must be developed under the Straight Fixed Variable (SFV) method of cost classification, allocation, and rate design unless the Commission permits the pipeline to use some other method; however, measures to mitigate cost shifts are required if the use of SFV will result in a 10 percent or greater increase in revenue responsibility for any historic customer class.

- Pipelines are granted blanket certificates for unbundled sales services and are subject to standards of conduct in connection with those services similar to those applicable to affiliate sales.[3] The

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3. Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, Order No. 497, 53 FR 22139 (June 14, 1988), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, 54 FR 52781 (Dec.22, 1989), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989), *order extending sunset date*, Order No. 497-B, 55 FR 53291 (Dec. 28, 1990), FERC Stats. & (Cont'd)

unbundled sale services are subject to pregranted abandonment.

° Existing bundled firm sales entitlements are converted to unbundled firm sales entitlements and to unbundled firm transportation rights on the effective date of the particular pipeline's blanket sales certificate. However, effective on that date, pipeline firm sales customers may reduce, in whole or in part, their firm sales entitlements. Pipeline customers may not reduce their firm transportation rights unless the pipeline executes a contract with another shipper for the transportation rights or agrees to the reduction or termination of the contractual rights.

In addition, in Order No. 636, the Commission (1) amended Section 284.221(d) of the Commission's regulations in further response to the remand of the United States Court of Appeals for the District of Columbia Circuit in *American Gas Association v. FERC*,[4] (2) concluded that pipelines should be able to recover 100 percent of their prudently incurred costs attributable to the transition required by Order No. 636, and (3) adopted measures governing the implementation of Order No. 636.

(Cont'd)

Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990), *order extending sunset date and amending final rule*, Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. & Regs. ¶ 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 18, 1992), 58 FERC ¶ 61,139 (1992), *aff'd in part and remanded in part*, Tenneco Gas v. FERC, No. 89-1768 (D.C. Cir. July 21, 1992).

4. 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S.Ct. 957 (1991).

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The Commission is largely upholding the regulations adopted in and requirements of Order No. 636 except for a number of changes in response to the petitions for rehearing. Among other things, as discussed below, the Commission is granting rehearing as follows. First, the Commission is requiring pipelines to maintain their one-part volumetric rates computed at an imputed load factor to determine the transportation rates for "small customers" (as discussed below) and is requiring pipelines, for a one-year period (from the effective date of the blanket sales certificate granted by Order No. 636), to sell gas to the small customers that elect to continue buying gas from the pipeline at a cost-based rate (based upon their actual price paid for gas). Second, the Commission is allowing, subject to certain restrictions, capacity releases for any period of less than one calendar month without prior posting on the electronic bulletin board or bidding for the released capacity. Third, while the Commission is requiring SFV for rate design (billing) and cost allocation purposes, it will allow the parties in the restructuring proceedings to consider the use of other ratemaking techniques to distribute revenue responsibility among customers, such as through the use of seasonal contract quantities or entitlements, if these ratemaking techniques help address significant cost shifts which might result from an allocation based only on peak day entitlements under SFV. Last, the Commission is requiring pipelines to recover 10 percent of their gas supply realignment costs from their Part 284 interruptible transportation service.[5] The explanation and

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5. As discussed below, the Commission encourages the pipeline and the parties to the restructuring proceedings to be creative in fashioning rate mechanisms, such as appropriate true-up mechanisms, that provide a reasonable opportunity for pipelines to recover (but not overrecover) those costs.

rationale for these adjustments are set forth below in the relevant sections.[6]

III. LEGAL BASIS AND RATIONALE FOR UNBUNDLING

This part III addresses the rehearing requests with respect to the Commission's legal basis and rationale for adopting Order No. 636.

A. The Legal Basis

The Commission, in Order No. 636, concluded that the pipelines' bundled, city-gate, firm sales service contravenes Natural Gas Act (NGA) sections 4(b) and 5. The Commission, therefore, as required, determined the remedial action necessary to remedy the violations of the statutory standards.[7] This remedy consisted, among other things, of altering existing bundled sales contracts into two separate contracts for unbundled sales and transportation.

Various rehearing petitioners argue that the Commission has acted beyond its statutory authority by revoking or modifying certificates of public convenience and necessity for bundled sales service, by mandating new services, and by unbundling direct sales. In addition, a few petitioners argue that the Commission has violated the Administrative Procedure Act (APA) and the U.S. Constitution.

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6. For ease of reference, the organization of this order continues to follow the organization of subjects used in Order No. 636.

7. Order No. 636, III FERC Stats. & Regs. Preambles ¶ 30,939 at p. 30,408-13.

Appendix C

1. Procedural Arguments

CNG Transmission Corporation (CNG) argues that Order No. 636 violates the Due Process Clause of the Constitution[8] and the procedural safeguards of the APA. [9] CNG asserts that those safeguards required the Commission to provide an opportunity for pipelines to comment on whether they can provide a reliable no-notice transportation service. ANR Pipeline Company (ANR) contends that Order No. 636 violated the APA because parties did not have the opportunity to show the lawfulness of their existing contracts. Southern Indiana Gas and Electric Company (Southern Indiana) also asserts the Commission did not provide due process to those affected by Order No. 636 because it failed to hold an evidentiary hearing, failed to follow the requirements of the NGA, exceeded its statutory authority and jurisdiction, and issued Order No. 636 without evidentiary support. Tenneco Gas (Tenneco) asserts that the Commission violated the notice and comment procedures of the APA by failing to properly address the comments made by the parties and failing to give notice of several aspects of the rule (*e.g.*, no-notice service).[10]

The Commission provided parties with an unprecedented input into the year-long development of the Notice of Proposed Rulemaking (NOPR), and thereafter, the final rule. There was more than an ample opportunity to comment on all aspects of

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8. U.S. CONST. amend. V.

9. 5 U.S.C. 553 (1988).

10. ANR argues, without specificity, that the Commission contravened the APA by relying in Order No. 636 upon material and conclusions that were not identified in the Notice of Proposed Rulemaking.

the rule, including no-notice transportation. First, the July 31, 1991 NOPR[11] was, among other things, the outcome of a public conference held on May 10, 1991, where participants in the natural gas industry discussed with the Commission the future role of interstate natural gas pipelines in the natural gas markets. Second, parties submitted initial comments and reply comments to the NOPR.

Some of those comments raised concern about the reliability of unbundled transportation service in meeting the needs of LDCs to serve their customers at peak. For example, in their initial and reply comments, many pipelines and LDCs maintained that unbundling would prevent pipelines from providing the reliable, firm, city gate service, *i.e.*, no-notice service, that they provided in the past. Most producers and marketers, on the other hand, claimed that pipelines could replicate the bundled, firm, city gate service, *i.e.*, no-notice service, in an unbundled environment. In response, on December 27, 1991, the Commission gave notice of a technical conference to discuss operational aspects of the NOPR and specifically the ability of pipelines to provide an unbundled no-notice delivery service as a remedy to the reliability concerns raised in the comments. The December 27th Notice included several specific questions to which the public could respond concerning no-notice transportation service.[12] The Commission held the technical conference on January 22, 1992. There was a wide-ranging discussion between the participants and the Commission

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11. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, 56 FR 38372 (Aug. 13, 1991), FERC Statutes and Regulations ¶ 32,480 (1991).

12. *See* 57 FR 385 (Jan. 6, 1992), III FERC Stats. & Regs. ¶ 35,022.

addressing various operational issues, including no-notice transportation service. In addition, parties were given the opportunity to file additional comments as a result of the technical conference. And while the issue of no-notice service may not have been designated as such at the beginning of this proceeding, the parties have focused specifically on operational issues and the need for a reliable no-notice service. Accordingly, the Commission in Order No. 636 required the no-notice transportation service as part of the mandatory unbundling remedy under NGA Section 5(a).[13]

The industry's comments therefore provided the Commission with a great deal of helpful information on what operational controls are required to provide no-notice transportation service in an unbundled environment. A representative of CNG, in particular, appeared at the technical conference and addressed the issue of why CNG needs to control storage hourly in order to provide no-notice service.[14] Furthermore, at the January 22, 1992 technical conference, the witnesses sponsored by the Interstate Natural Gas Association of America (INGAA), which included representatives of various pipelines, conceded that pipelines could provide no-notice transportation service if they retained certain operational controls over their systems. That all these parties commented on all aspects of no-notice service signifies that they had adequate notice of this issue.

The Commission has adequately addressed the comments of the parties. The Commission, in Order No. 636, outlined the

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13. See the more detailed discussion in Order No. 636 at pp. 30,406-30,409.

14. Technical Conference Tr. 73-77.

proposal in the NOPR on each issue, discussed the comments of the parties on the issue, and gave the reasons why it reached a particular outcome on each issue. The APA does not require an agency to respond to every fact or contention in the comments submitted, but only requires the agency to "respond[] to significant points raised by the public."[15]

Colorado Interstate Gas Company (CIG) argues that Order No. 636 did not comply with the APA's official notice requirements with respect to the data relied upon by Order No. 636. CIG maintains that it is entitled to a hearing to test the accuracy of the data relied upon by the Commission, and to determine whether the data permit a conclusion other than that drawn by the Commission.

CIG is incorrect in its assertion that the Commission failed to follow the requirements of the APA. CIG relies on 5 U.S.C. § 556, which does not apply to this proceeding.[16] This proceeding is a notice and comment rulemaking proceeding governed by 5

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15. *See* Home Box Office v. FCC, 567 F.2d 9, 35-36, (D.C Cir. 1977), *cert. denied*, 434 U.S. 829 (1977). (Footnote omitted).

16. Section 556(e), which was only *partially* quoted by CIG, states in full:

> The transcript of testimony and exhibits, together with all papers and requests filed in the proceeding, constitutes the exclusive record for decision in accordance with section 557 of this title and, on payment of lawfully prescribed costs, shall be made available to the parties. When an agency decision rests on official notice of a material fact not appearing in the evidence in the record, a party is entitled, on timely request, to an opportunity to show the contrary.

U.S.C. § 553. That section applies since the Commission is not required by statute to hold a hearing in order to promulgate a rule. Section 553 states:

> After notice required by this section, the agency shall give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments with or without opportunity for oral presentation. After consideration of the relevant matter presented, the agency shall incorporate in the rules adopted a concise general statement of their basis and purpose. When rules are required by statute to be made on the record after opportunity for an agency hearing, sections 556 and 557 of this title apply instead of this subsection.

Moreover, CIG has offered nothing to warrant the need to hold a hearing about the accuracy of the data used by the Commission in Order No. 636. Those data, garnered from INGAA, the Energy Information Administration (EIA), reports filed with the Commission, and other publicly available sources can be assumed to be accurate, especially since CIG has not offered anything to suggest the contrary. CIG merely asserts that the Commission erred by not holding a hearing. Hearings are held to establish disputed facts and are not needed to ventilate comparisons and conclusions.[17]

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17. *See* Cities Service Gas Company v. Federal Power Commission, 553 F.2d 1278, 1290 (D.C. Cir. 1976), where the court stated that it is a "settled rule that where there are no genuine, relevant, material, factual questions in dispute the [Commission] may proceed under sections 4 and 5 of the Natural Gas Act without formal evidentiary hearings." *See also* Mobil Oil Corp. v.

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Appendix C

2. Natural Gas Act Authority

CIG, Arkla, Inc. (Arkla), Tenneco, Cincinnati Gas & Electric Company, *et al.* (Cincinnati Gas),[18] and Natural Gas Pipeline Company of America (Natural), argue that the Commission exceeded its authority under NGA section 5 to modify or revoke a pipeline's certificate issued under NGA section 7. For example, Arkla states that NGA section 5 does not vest the Commission with the authority to cancel unilaterally a certificated service without the pipeline's consent. Similarly, Cincinnati Gas and Natural argue that this change is too fundamental to be viewed as anything but a certificate revocation. Tenneco maintains that the Commission may not revoke a certificate absent a violation of the certificate's conditions. Cincinnati Gas adds that the Commission consistently recognized the limitations of its NGA section 5 authority, and the need for action under NGA section 7 when there is a significant modification in the type or kind of service that a pipeline offers. Finally, Arkla contends that the Commission can satisfy NGA section 5 only by holding a hearing, collecting evidence, and making individualized findings.

As the Commission stated in Order No. 636, the Commission rejects contentions that its action under NGA

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Federal Energy Regulatory Commission, 886 F.2d 1023, 1033 (8th Cir. 1989), where the court stated "FERC is not required to hold evidentiary hearings where only questions of law and policy are matters in controversy[;]" and Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1168 n. 41 (D.C. Cir. 1985), *cert. denied*, 476 U.S. 1114 (1986) (court rejected contentions that the "after a hearing" requirement found in NGA section 5 must be satisfied through a formal, trial-type hearing).

18. Cincinnati, Union Light, Heat and Power Company, Lawrenceburg Gas Company, and Mountaineer Gas Company filed a joint petition.

Section 5 violates NGA Section 7 because the Commission lacks the authority to revoke, suspend, or adversely modify an issued and accepted certificate.[19] To the contrary, the Commission's action is within its authority under NGA Section 5 to alter a pipeline's contractual terms and conditions of service to remedy an unlawful practice.[20]

The Commission adheres to its analysis and conclusion in Order No. 636 that its action under NGA section 5 is not an unlawful revocation or modification of a certificate of public convenience and necessity under NGA section 7. Section 7 cannot be read so narrowly as to permanently prevent the Commission from changing the terms and conditions under which a pipeline provides service, especially when the pipeline's obligation to serve and the LDC's entitlement under the certificate remain intact. Such a narrow reading of section 7 would prevent the Commission from making adjustments, contemplated by section 5, to the terms and conditions under which pipelines provide service when the Commission finds it necessary to satisfy the standards of the NGA in light of changing circumstances.

In this case, the regulations retain in an altered manner the LDC's entitlement to service and the pipeline's authorization and obligation to provide service.[21] An LDC and a pipeline are

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19. Order No. 636 at p. 30,422.

20. *Id.* at p. 30,423, *citing* Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1153 n.9 (D.C. Cir. 1985), *cert. denied*, 476 U.S. 1114 (1986); Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 389 (1959); and Transwestern Pipeline Co. v. FERC, 820 F.2d 733, 746 (5th Cir. 1987), *cert. denied*, 484 U.S. 1005 (1988).

21. For example, a pipeline must provide no-notice transportation

(Cont'd)

thus presented with two options. First, an LDC and a pipeline may agree upon the price for gas to be sold on an unbundled basis, while the firm transportation of gas to the city-gate under no-notice transportation service would continue to be priced under traditional ratemaking methods. Thus, their relationship would continue under the new terms and conditions of the pipeline's blanket transportation and blanket sales certificates. The pipeline's certificated obligations with respect to individual services are, in essence, merged into or subsumed within the pipelines' blanket certificates. Under the second option, if an LDC and a pipeline do not enter into an agreement pursuant to the procedures in Order No. 636, then and only then would the pipeline's *sales* service obligation cease as of the effective date of the tariff sheets filed in compliance with this rule. However, the pipeline must continue to provide transportation services to that customer, who, with the equality of transportation principles imposed here, is assured the ability to maintain reliable service.

Finally, Arkla's contention that the Commission can satisfy NGA section 5 only by holding a hearing, collecting evidence, and making individualized findings is without merit. In *Wisconsin Gas Co. v. FERC*,[22] the court specifically rejected contentions that the "after a hearing" requirement found in NGA section 5 must be satisfied through a formal, trial-type hearing.

The American Public Gas Association (APGA) contends that the Commission has violated NGA section 7(a) by abolishing

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service to customers receiving a no-notice, bundled, city-gate, firm sales service on the effective date of the rule.

22. 70 F.2d 1144, 1168 n. 41 (D.C. Cir. 1985), *cert. denied*, 476 U.S. 1114 (1986).

bundled firm sales service.[23] It argues that the Commission has effectively repealed that section, which grants the Commission the authority to compel sales but not transportation services. Kentucky Ohio Gas Company (Kentucky Ohio) argues that the Commission must make clear that it will exercise its authority under NGA Section 7(a) to order pipeline interconnections with an LDC or municipality even when the LDC or municipality does not desire to purchase gas from the pipeline.

Pacific Gas Transmission Company (PGT), ANR, CNG, Tenneco and Arkla argue that the Commission is without authority to compel the pipelines to provide new services, such

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23. NGA Section 7(a) provides:

> Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural gas or artificial gas to the public, and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company, if the Commission finds that no undue burden will be placed upon such natural-gas company thereby: *Provided*, That the Commission shall have no authority to compel the enlargement of transportation facilities for such purpose, or to compel such natural-gas company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers.

as open access storage, no-notice transportation, capacity releasing, and unbundled sales. For example, Arkla argues that NGA section 7 implicitly limits the Commission's ability to compel the provision of services. It argues that Congress would have had no reason to authorize the Commission to compel service under section 7(a), if the Commission could compel service under section 5(a). Arkla contends that the Commission's reliance on section 5(a) renders section 7(a) surplusage. Arkla also cites several Commission orders that required NGA section 7 action by pipelines to change service.[24] Similarly, CNG argues that the Commission has no authority under the NGA to order pipelines to provide new services that compel it to share assets (*e.g.* storage facilities).

Under NGA section 7(a), the Commission may order a pipeline to sell gas to a local distributor if the Commission finds it necessary or desirable in the public interest.[25] Contrary to the assertions of the petitioners, the Commission does not read section 7(a) as limiting the Commission's ability to act under section 5, as it has done in this proceeding. Section 7(a) establishes the standards the Commission must apply to require a pipeline to provide sales service to an LDC. The powers granted by Congress to the Commission in sections 7(a) and section 5 are separate and distinct, albeit complementary. Neither the purposes nor the terms of section 7(a) prevent the

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24. *E.g.*, Panhandle Eastern Pipe Line Co., 57 FERC ¶ 61,265 at p. 61,862 (1991) (changes in contract demand level); South Georgia Natural Gas Co., 48 FERC ¶ 61,383 at p. 62,539 (1989) (abandonment of standby service); Alabama Tennessee Natural Gas Co., 53 FERC ¶ 61,032 (1990) (service change from sales to sales-transportation).

25. *See* Rural Energy Systems, Inc., 34 FERC ¶ 61,389 at p. 61,723 n. 12 (1986).

Commission from assuring, once service to individual markets and territories has been established, that the protection against undue discrimination in service provided by sections 4, 5, and 7 of the NGA are available. First, section 7(a) applies only to new sales. It does not prevent the Commission from requiring changes in existing sales services. Second, the Commission is not compelling service in Order No. 636. The Commission is changing the terms of existing services and establishing through the procedures established by Order No. 636 the terms for future services. Even if the Commission is compelling the pipelines to provide "new" services to its open access transportation customers, it has the authority to do that in order to remedy undue discrimination.[26]

The Commission has exercised its authority under section 5 to find the pre-Order No. 636 regulatory structure, which includes the terms of existing services, unduly discriminatory and anticompetitive. The Commission has the authority under NGA section 5 to authorize the just and reasonable terms and conditions for the interstate transportation and sale for resale of natural gas. The requirements of Order No. 636 are all necessary to ensure that Part 284 transportation is performed on a just and reasonable, nondiscriminatory basis with respect to all gas supplies. Finally, the Commission's authority to compel sales service is discretionary. The Commission sees no reason, at this time, to determine whether at some future time it will compel a new sales service under section 7(a), and under what terms and conditions of service.

Arkla's argument that the Commission's reliance on section 5(a) renders section 7(a) surplusage is incorrect. The purpose

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26. Associated Gas Distributors v. FERC, 824 F.2d 981, 1000 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

of section 7(a) was to make it possible for communities that had no natural gas service to buy natural gas service from unwilling pipelines.[27] Thus, that section only authorizes the Commission to compel a pipeline to provide sales service (and to construct and operate facilities for that purpose). It relates to initiating a new sales arrangement rather than changing existing arrangements. How that section will or should be applied within the regulatory framework adopted in Order No. 636 is an issue the Commission leaves open for another day. Simply stated, section 7(a) does not prevent the Commission from prescribing reasonable terms and conditions of service under NGA section 5 as they relate to existing certificated service including sales and Part 284 transportation services.

The petitioners are incorrect in their assertion that the Commission lacks the authority to require pipelines to provide open access storage. First, the Commission has always regulated storage as part of its jurisdiction over interstate transportation.[28] Second, in Order No. 636, the Commission found the pipelines' bundled, city-gate, firm sales service to be unduly discriminatory under NGA sections 4(b) and 5(a). As part of the remedy the Commission concluded it was appropriate to regulate storage under Part 284 of the regulations. In Order No. 636, the Commission found that the pipelines' superior rights with respect to access and control of storage provide them with advantages

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27. *See* Rural Energy Systems, Inc., 34 FERC ¶ 61,389 at p. 61,722, *citing* Central Illinois Public Service Co. v. FPC, 338 F.2d 682, 687 (7th Cir. 1964).

28. *See* Texas Gas Transmission Corporation, 26 FERC ¶ 61,150 at p. 61,395 (1984) ("[W]e have viewed storage to be within the Commission's transportation jurisdiction under the Natural Gas Act and the Natural Gas Policy Act of 1978 (NGPA).").

over other gas merchants. The pipelines' ability to use storage for seasonal supply management, as a supplement to transmission capacity, and to maintain a constant flow of gas, give pipelines an unfair advantage over other gas merchants because they do not have the flexibility to provide fully a sales service which meets gas purchasers' peak needs. Access to storage is a key component of establishing equality of transportation, without it, pipelines' service will remain superior to other services that can be offered. Because the Commission is requiring the unbundling of pipeline sales and transportation services, pipelines with storage capacity downstream of the place it unbundles will need it only to fulfill their obligations with respect to system management (load balancing) and no-notice transportation service. Pipeline customers, of course, must have access to that storage to build their own gas supply portfolio and determine which services they need to replace pipeline bundled, city-gate, firm sales service. In addition, access to storage for pipeline customers such as LDCs will help them achieve a more efficient load profile between peak and offpeak seasons. For example, an LDC will be in a better position to buy, ship, and store gas in the summer for use in the winter instead of buying that gas from the pipeline in the winter.

The argument that the Commission is unlawfully requiring pipelines to provide new services that compel them to share assets (*e.g.* storage facilities) is without merit because the Commission is not compelling a new service. The no-notice transportation service will be similar to the transportation service imbedded in pipelines' current, bundled, firm sales service. Because, among other things, the Commission is unbundling the sale of gas from existing service by moving the point of sale as far upstream as possible, pipelines will not require the same amount of storage as they have in the past. However, the

Commission recognized that pipelines would require a certain amount of storage to provide no-notice transportation service and for load balancing purposes. After the amount of storage capacity needed by the pipeline is determined, the remaining storage capacity must be offered on an open access, nondiscriminatory basis because the Part 284 regulations will include storage within the definition of transportation. Further, it should make good business sense for a pipeline to allow shippers and other gas merchants to obtain the storage capacity that it no longer needs because it will be operating in an unbundled environment. Finally, the petitioners are also incorrect in their assertion that the Commission lacks the authority to require pipelines to provide no-notice transportation service. The Commission, pursuant to NGA section 5, found bundled, city-gate, firm sales service to be unduly discriminatory and preferential. As a remedy, the Commission determined that a just and reasonable practice would be the separate provision of no-notice transportation service embedded within the bundled sales service. The Commission found that this requirement was necessary so that a customer could receive its natural gas supplies in a fashion as reliable as the customer had been receiving under a bundled, city-gate service, with the added advantage of providing greater opportunities to purchase that supply at competitive prices from other sellers. The Commission is separating existing service into two parts. As discussed above, it is not compelling a new service because it is just separating the sale of gas from the existing service.

3. Direct Sales

Arkla contends that the Commission lacks the authority to cancel or modify nonjurisdictional sales contracts under any

circumstances,[29] and therefore, Order No. 636 must be modified to exclude nonjurisdictional, direct sales contracts from mandatory unbundling.

In *Panhandle Eastern Pipe Line Co. v. Public Service Commission of Indiana*,[30] the Supreme Court discussed the Commission's jurisdiction under section 1(b) of the Natural Gas Act. The Court stated:

> Three things and three only Congress drew within its own regulatory power, delegated by the Act to its agent, the Federal Power Commission. These were: (1) the transportation of natural gas in interstate commerce; (2) its sale in interstate commerce for resale; and (3) natural gas companies engaged in such transportation or sale.[31]

In *FPC v. Louisiana Power and Light Co.*,[32] which concerned pipelines' curtailment plans, the Supreme Court further clarified the Commission's jurisdiction under section 1(b) of the Natural Gas Act. The court stated:

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29. *Citing* Regulations of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 500-H, FERC Stats. and Regs. ¶ 30,867 at 31,540 (1989), *aff'd*, American Gas Association v. FERC, 912 F.2d 1496, 1507 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991) (The Commission has no authority to abrogate nonjurisdictional producer/pipeline contracts.)

30. 332 U.S. 507 (1947).

31. *Id.* at 516.

32. 406 U.S. 621 (1971).

> [T]he prohibition of the proviso of § 1(b) withheld from FPC only *rate-setting* authority with respect to direct sales. Curtailment regulations are not *rate-setting* regulations but regulations of the "transportation" of natural gas and thus within FPC jurisdiction under the opening sentence of § 1(b) that "[t]he provisions of this Act shall apply to the transportation of natural gas in interstate commerce[.][33]

Since the transportation component of a direct sale is within the Commission's jurisdiction, and since the requirement that sales must be unbundled from transportation does not establish a rate for the unbundled direct sale, the Commission has the authority to require pipelines to unbundle their nonjurisdictional direct sales from the jurisdictional transportation service embedded in that sale.[34] The Commission believes that a pipeline's direct sale of gas should be unbundled from the transportation of such gas, just as all other pipeline sales will be unbundled from transportation, because of the possibility that the jurisdictional transportation service embedded in the direct sales transactions may cause direct sales customers to prefer the pipeline's sales over sales from non-pipeline gas merchants. Finally, nothing in Order No. 636 should be read as affecting the rates that pipelines may charge for gas in a direct sales transaction.

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33. *Id.* at 637-38.

34. Mississippi River Transmission Corp. v. FERC, No. 91-1164 (D.C. Cir. July 21, 1992). (The Commission's authority over the transportation of gas in connection with an unregulated direct sale "is beyond dispute." Slip op. at 4).

4. Contracts

Tenneco argues that the Commission has disregarded private contracts by not showing that the bundled sales contracts adversely affect the public interest. CIG argues that the Commission has shown indifference to the sanctity of contracts that reflects fundamental and long-standing commercial relationships. CNG asserts that the Commission has disregarded the fundamental role of freely negotiated contracts. In addition, ANR and CNG assert that the Commission is unlawfully creating contractual relationships for the parties.

The Commission clearly has the authority to require changes in the contracts between interstate pipelines and their customers. As the Supreme Court held in *United Gas Co. v. Mobile Gas Corp.*:[35]

> The basic power of the Commission is that given it by § 5(a) to set aside and modify any rate or contract which it determines, after hearing, to be "unjust, unreasonable, unduly discriminatory, or preferential." . . . It is simply the power to review rates and contracts made in the first instance by natural gas companies and, if they are determined to be unlawful, to remedy them.[36]

The Commission has exercised this authority in Order No. 636 and has found pipeline bundled sales services to be unduly discriminatory and anticompetitive, and accordingly, has, among

35. 350 U.S. 332 (1956).

36. *Id.* at 341.

other things, changed the bundled sales contracts of pipelines into separate contracts for sales and transportation. A contract which is found to be unduly discriminatory by its very nature adversely affects the public interest and *must* be modified.

Contrary to the assertions of CIG and CNG, the Commission is not disregarding the role of contracts. In fact, one of the goals of the final rule is to allow parties to rely more on private contracts. The Commission stated in Order No. 636 that "[a]s part of the effort to foster competition in the natural gas industry, the Commission, in the final rule, is allowing the industry greater flexibility to control transactions through negotiated contracts."[37] But to achieve this objective in a manner that enables consumers to realize the long term benefits of fair competition, Order No. 636 changes parties' existing unduly discriminatory contracts.[38] As a result, the new regulatory structure created by Order No. 636 will enable parties to rely more on contracts to govern their relationships in the future and thus will occur in a commercial environment where no one segment of the industry has an unfair, regulatory advantage over other market participants. Finally, contrary to the assertions of ANR and CNG, the Commission is not unlawfully creating new contractual relationships for the parties. The Commission, by changing the terms and conditions under which service will be provided, has presented LDCs and pipelines with the option of continuing their relationship under the new regulatory structure or terminating their relationship altogether. Order No. 636 has, however, created a new regulatory structure which will enable parties to enter into new contractual relationships that serve the public interest.

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37. Order No. 636 at p. 30,444.

38. Office of Consumers' Counsel v. FERC, 783 F. 2d 206, 236 (D.C. Cir. 1986).

Appendix C

5. Record Evidence

Several petitioners, such as Arkla, ANR, Natural, CNG and Tenneco, assert that the Commission's decision to require pipelines to unbundle and offer no-notice transportation service is not based on substantial record evidence.

The Commission disagrees. The Commission's decision to require pipelines to unbundle their sales was based upon facts showing that the market was operating inefficiently, disadvantaging all segments of the industry and the consumer. These facts, which are reflected in the various tables contained in Order No. 636, show that a disproportionate amount of firm pipeline capacity is reserved for firm sales, but that pipeline sales customers prefer to buy their gas from other sellers, and have it transported using interruptible transportation, or inferior firm transportation. The 1991 Part 284 Capacity Reports for major pipelines that made bundled sales show that an average of 64.1 percent of the pipelines' total firm capacity was reserved for firm sales.[39] However, sales only accounted for an average of 18.8 percent of the total throughput on these major pipelines. These facts led the Commission to conclude that bundled sales service was causing the natural gas market to operate inefficiently, and therefore, pipeline sales should be provided separately from transportation.

In addition, as discussed elsewhere in this order and in Order No. 636, the participants in the natural gas industry, including pipelines, generally agreed at the January 22, 1992 technical conference and the comments following that conference, that no-notice transportation service could be provided by pipelines

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39. Table 2 of Order No. 636 at p. 30,399. See discussion below of Table 2.

if they retain certain operational controls over their systems. The Commission, therefore, finds that its decision to require unbundling and the provision of no-notice transportation service is based upon substantial evidence and facts in the record of this proceeding.

6. Takings Clause Arguments

CNG argues that Order No. 636 violates the Takings Clause of the Fifth Amendment to the Constitution[40] by effectively terminating sales contracts and requiring the assignment of upstream capacity to downstream firm shippers without just compensation. Natural argues that, by precluding pipelines from making bundled sales when marketers can do so, Order No. 636 is an unlawful taking without compensation because the pipelines are deprived of an ability to act efficiently as sellers.

These arguments are based on a mischaracterization of Order No. 636. First, the Commission is not effectively terminating sales contracts. As discussed above and in Order No. 636, the Commission is separating the components of bundled sales contracts into unbundled sales contracts and firm transportation contracts. Because the regulations retain the LDC's entitlement to service and the pipeline's obligation to serve, an LDC and a pipeline may agree upon the price for gas, and the firm transportation of gas to the city-gate under the no-notice transportation service. Thus, their relationship would continue under the new terms and conditions of the pipeline's blanket transportation and blanket sales certificate.

With respect to the assignment of upstream capacity to downstream firm shippers, those shippers who want upstream

40. U.S. CONST. amend. V.

capacity will be required to pay for it. If the upstream capacity is valuable to the pipeline now, it will probably be valuable to downstream shippers in the restructured environment. In addition, to the extent downstream pipelines retain unclaimed or unneeded upstream capacity even after the assignment of capacity to firm shippers, the pipeline may file to recover such "stranded" costs in an NGA section 4 filing.

Contrary to Natural's assertion that pipelines cannot act efficiently as gas sellers in an unbundled environment, pipelines will be offering the same services in the same market as other gas sellers and will be able to compete at market prices under their blanket certificates. If a firm sales customer is satisfied with its sales service, it will probably elect to continue its contractual relationship with the pipeline under the new blanket sales certificate. When a pipeline is in full compliance with Order No. 636, it will be permitted to make market-based sales under its blanket certificate. The Commission recognized that market-based pricing for unbundled sales is necessary for pipelines to compete with non-pipeline gas merchants. In addition, pipelines are not on a par with other gas sellers because of the pipelines' monopoly control of essential transportation facilities. A goal of Order No. 636 is to create an environment in which pipelines sell under similar conditions as other gas sellers so that pipelines are unable to prefer their own gas sales because they control the transportation of gas.

In sum, because Order No. 636 does not deprive pipelines of the ability to do business, but, in fact, enhances their opportunities, there is no factual foundation to reach the "takings" argument.

Appendix C

B. The Rationale

In Order No. 636, the Commission concluded that the pipelines' bundled, city-gate, firm sales service violates sections 4(b) and 5(a) of the NGA because of the unreasonable difference between the quality of the transportation embedded within the pipelines' bundled, city-gate, firm sales service and the quality of the pipelines' open access firm transportation service. In Order No. 636, the Commission described the adverse impact of that difference in quality on all segments of the natural gas industry. First, nonpipeline gas sellers are at a disadvantage *vis a vis* pipeline gas merchants in securing long-term gas supply arrangements because the nonpipeline gas sellers cannot assure delivery at the city-gate in all circumstances. This is so because the nonpipeline gas merchants' gas must move to the city gate through interruptible or inferior firm transportation. However, pipelines do not totally benefit from this situation. Indeed, the Commission showed that pipelines are disadvantaged. Pipelines must stand ready to provide gas on demand at cost-based rates that do not enable the pipelines to successfully compete with unregulated gas sellers for sales customers on an annual basis. Last, gas customers are disadvantaged because they must use interruptible transportation to move their nonpipeline gas purchases even though they are paying firm sales demand charges for the firm transportation that is embedded within the firm sales service.[41]

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41. As cited by the Commission in Order No. 636, 51 percent of the pipeline deliveries to market were through interruptible transportation as compared to deliveries to market of 21 percent pipeline sales and 28 percent firm transportation. Interstate Natural Gas Association of America, Issue Analysis: Carriage Through 1991 (May 1992), from: Table A-7, Sales and Firm and Interruptible Transportation as a Percentage of Total Delivered for Market (INGAA May 1992 paper). The INGAA May 1992 paper shows that,

(Cont'd)

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Only a handful of the rehearing petitioners dispute the Commission's rationale for taking action under NGA sections 4(b) and 5(a). Those objections are discussed below.

1. Antitrust Criteria

CNG and Carnegie Natural Gas Company (Carnegie) argue that the Commission did not perform a proper competition analysis under relevant antitrust criteria to determine whether pipelines possess market power in the relevant markets and whether the pipelines' bundled sales service is justified by a legitimate business purpose. On the other hand, Tenneco asks the Commission to retract its finding that the bundled city-gate service is an unlawful restraint of trade because Tenneco maintains it unjustly implies a violation of the Sherman Antitrust Act.[42]

The Commission acts under NGA sections 4 and 5 to declare pipeline practices lawful or unlawful and, if unlawful, to prescribe appropriate remedies; the Commission "does not enforce or apply the antitrust laws."[43] In applying the NGA, of course, the Commission considers the policies underlying the antitrust laws, including the anticompetitive effects of interstate pipeline operations.[44] While the Commission may employ an

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in 1991, 54 percent of the deliveries to market used interruptible transportation as compared to deliveries to market of 16 percent pipeline sales and 30 percent firm transportation.

42. Petition at 6.

43. Transwestern Pipeline Co. v. FERC, 820 F.2d 733, 741 (5th Cir. 1987).

44. *Cf.*, Gulf States Util. Co. v. FPC, 411 U.S. 747, 758-760 (1973).

analysis similar to that used in antitrust cases, the Commission does not reach or imply conclusions about violations of the Sherman Antitrust Act or any other antitrust law.

In addition, the Commission's conclusions in Order No. 636 *vis a vis* anticompetitiveness and restraint of trade should not be interpreted to imply for specific transactions any violation of the antitrust laws by pipelines. The Commission's findings and conclusions are made solely under NGA sections 4(b) and 5(a).

Finally, Congress' underlying premise in enacting the NGA was that the pipelines possessed market power in providing services. That remains true today and is the starting point for the Commission's analysis. [45] Any pipeline — including CNG — that wishes to show that it lacks monopoly or market power over its customers in the transportation services it provides is free to do so. CNG has not done so here.

2. Anticompetitive Finding

Tenneco asserts that there is no record support for the Commission's conclusion that "pipelines are exercising monopoly power at the expense of consumers."[46] Tenneco refers to the small amount of pipeline gas sales (21 percent), to the current low price of gas, and to the abundant amount of divertible gas supplies. Tenneco further contends that the failure of sales customers to convert to firm transportation was caused by the Commission's pregranted abandonment policy and not by

45. Pipelines "have market power over transportation service." Tenneco Gas v. FERC, No. 89-1786, slip. op. at 18 (D.C. Cir. July 21, 1992).

46. Petition at 4.

pipeline monopoly power. Tenneco claims that if the pipelines had monopoly power even fewer conversions would have occurred and that "conversions on individual pipelines offering bundled city-gate sales have been higher than [the] 24%" cited by the Commission.[47]

Even though CNG's contentions, as discussed in the preceding subsection, are inappropriately draped in antitrust criteria, the Commission believes it appropriate to respond to CNG's argument. CNG maintains that the statistics cited by the Commission in Order No. 636, in support of its anticompetitiveness finding, are not relevant and that the Commission has erroneously concluded that pipelines have a competitive advantage via their bundled sales service even though the pipelines are not the beneficiaries.

Atlanta Gas Light Company and Chattanooga Gas Company (Atlanta Gas) contend that the Commission has improperly relied on NGA section 5(a), a consumer protection measure,[48] to protect producers. Citizen Action similarly argues that the Commission is attempting to pass off an anti-residential consumer policy as helping consumers. Citizen Action further maintains that residential and small gas consumers cannot yet make any informed choices about purchasing gas. The National Association of State Utility Consumer Advocates (NASUCA) contends that the order will benefit large industrial and electric utility users.

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47. *Id.* at 5. Tenneco notes that "[o]n Tennessee's system, for example, 94 percent of customers have converted all or a portion of their contract demand, resulting in conversion of 50% of total sales contract demand." *Id.* n. 9.

48. *Citing* Atlantic Reg. Co. v. Public Service Commission of New York, 360 U.S. 376, 388 (1979).

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The Commission adheres to its discussion and analysis in Order No. 636 with respect its conclusions under NGA sections 4 and 5 and, therefore, will not repeat that detailed discussion and analysis here. The Commission will, however, for emphasis, discuss a few matters.

The Commission's statutory mandate is to protect consumers of natural gas from the exercise of monopoly power by pipelines[49] in order to assure consumers "access to an adequate supply of gas at a reasonable price."[50] In addition, the Commission must protect the interests of the investors in the pipeline by providing the pipeline an opportunity to earn a return which will "be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[51] As the Commission stated in Order No. 636, those consumer and investor interests must be balanced,[52] in light of the current economic, regulatory, and market realities.[53]

In Order No. 636, the Commission demonstrated that the pre-Order No. 636 structure of the pipeline industry is dysfunctional and impairs the efficient functioning of the natural

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49. FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944); Associated Gas Distributors v. FERC, 824 F.2d 981, 995 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988) ("The Natural Gas Act has the fundamental purpose of protecting interstate gas consumers from pipelines' monopoly power.").

50. Tejas Power Corp. v. FERC, 908 F.2d 998, 1003 (D.C. Cir. 1990).

51. FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

52. *Id.* ("The rate-making process under the [NGA] . . . involves a balancing of the investor and consumer interests.")

53. Order No. 636 at p. 30,392.

gas market with respect to all segments of the natural gas industry. That pipelines have a low share of *annual* sales and have not reaped all of the benefits does not vitiate the Commission's analysis. The Commission's focus is on the bundled, city-gate, firm sales service, and capacity reserved for that service, its unduly discriminatory nature *vis a vis* firm transportation, and the anticompetitive consequences for all segments of the industry and consumers.

The Commission believes that the statistics cited in Order No. 636 are significant because they show that, as a group, pipeline customers have not converted to firm transportation service to satisfy their needs but have, instead, retained the higher quality bundled sales service to meet their peak needs on demand. While the Commission's pregranted abandonment policy may have influenced those customers, that does not detract from the conclusion that pipeline customers have kept the annual bundled sales service to guarantee deliveries to meet their peak needs. As the Commission stated in Order No. 636, this is amply proven by the comments of those opposing mandatory unbundling.[54] Indeed, if true, Tenneco's position underscores the market power pipelines possess in transporting gas to the city-gate. Because pipelines — and only pipelines — under the pre-636 regulatory rules can deliver gas under no-notice bundled service, they, and only they, could offer superior service. Customers may have been reluctant to leave that bundled gas service because they have no other meaningful transportation alternatives. Thus, Tenneco's argument admits by implication the factual premise that led to the remedy in Order No. 636. The Commission has acted here to ensure that pipeline customers can continue to get guaranteed deliveries to meet their peak needs, but without having to buy from only one seller. The

54. *Id.* at p. 30,402.

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Commission's intent in Order No. 636 was to eliminate the unfair competitive advantage held by pipelines' bundled city-gate, firm sales service because pipelines provide their competitors for gas sales with access to a lower quality firm transportation service than that embedded within their bundled, city-gate, firm sales service.[55] Pipeline customers have chosen to retain their bundled, firm sales service and pay reservation charges to ensure that they can meet their peak needs. This is the case even though most customers prefer to buy gas throughout the year from other gas sellers and have it transported under interruptible transportation service.

Of course, some pipelines have had more conversions than other pipelines. But this is to be expected as part of the evolution of the natural gas industry discussed in Order No. 636. In any event, this does not eliminate the need to take generic action to complete that evolution to maximize the benefits of the Natural Gas Wellhead Decontrol Act (Decontrol Act).[56] It is necessary that the pipeline industry as a whole complete its evolution so as to ensure there is no obstacle to the consumers' access to a natural gas pipeline grid and to the blossoming national gas market.

The Commission rejects the contentions that it is acting to protect only producers or industrials or electric utility users and not residential or other gas consumers. As with Order No. 436, Order No. 636 "seeks to guarantee that the competitive conditions that now obtain in the 'wellhead' or gas-production

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55. *Cf.* Tenneco Gas v. FERC, *supra*, slip. op. at 27-28, quoting the Department of Justice on the adverse impact of a lower quality access on the ability of competitors of pipelines to compete.

56. Pub. L. 101-60, 103 Stat. 157 (1989).

market will redound to the benefit of gas consumers."[57] This will be accomplished by creating non-discriminatory no-notice transportation so that LDCs can buy gas directly from any seller of natural gas and receive an adequate and reliable supply of gas at reasonable prices in order to serve all of their customers, including residential. In Order No. 636, the Commission created a complete menu of services for all firm shippers, including LDCs, so that they can fashion arrangements best suited to meet their needs based on informed choices about the services that are available. This is in lieu of the pre-Order 636 system that binds together individual services with separate costs into one bundled service.

3. Purpose of Bundled Sales Service

Both CNG and Carnegie further argue that the Commission erred by not considering whether bundled sales service is justified by legitimate business purposes (*e.g.*, enhancing efficiency).

The Commission was not blind to the legitimate business purpose of bundled sales service. Indeed, the Commission recognized that the objective of that service — to allow firm sales customers to receive gas up to their daily contract entitlements on demand without nominating that amount or incurring a penalty — was in the public interest. However, the Commission determined that the legitimate business purpose of bundled sales service was outweighed by its anticompetitive harm because no-notice transportation could be provided for unbundled sales without the harm resulting from the bundled sales service.

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57. Panhandle Eastern Pipe Line Co. v. FERC, 890 F. 2d 435, 436 (D.C. Cir. 1989).

Moreover, CNG and Carnegie have made no attempt to quantify the efficiencies that would be lost by the unbundling of pipeline sales from pipeline transportation. It was up to them to come forward with quantifiable data to support their claim.[58] Hence, the Commission remains convinced that its action in Order No. 636 will deter and prevent the anticompetitive abuse of the bundled sales service and, at the same time, preserve the no-notice benefits of that service. That is, the Commission upholds its conclusion that unbundled sales combined with no-notice transportation is an adequate substitute for bundled sales service[59] that also provides additional benefits to the natural gas industry.[60]

4. Cost-Benefit Analysis

CNG, Carnegie, the PEC Pipeline Group (PEC Group),[61] Atlanta Gas, Illinois Power Company and Northern States Power Companies (Illinois Power) contend that the Commission did not weigh the benefits of unbundling against the costs of unbundling. For example, Illinois Power argues that the Commission erred because it did not quantify the alleged benefits of unbundling or factor into the analysis the transition costs likely

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58. *See, generally* Tenneco Gas v. FERC, *supra*, slip. op. at 34-35 and the cases cited therein.

59. *See generally* Mississippi River Transmission Corp., *supra*, slip. op. at 10.

60. Order No. 636 at pp. 30, 411-12.

61. The PEC Pipeline Group consists of Texas Eastern Transmission Corporation, Panhandle Eastern Pipe Line Company, Trunkline Gas Company and Algonquin Gas Transmission Company.

to result from unbundling sales service. In particular, Illinois Power argues that there is no support for the Commission's assertion that the Commission "does not *anticipate* that pipeline gas supply costs that are incurred as a result of implementing this rule will approach the order of magnitude of the take-or-pay liabilities of . . . [the Order No. 500 and 528] era."[62]

Atlanta Gas and Citizen Action argue that an analysis prepared by the Commission's Office of Economic Policy (OEP) with respect to the benefits of Order No. 636 must be made available and part of this proceeding.

The Commission is not required to "make specific findings of tangible benefits."[63] However, two points should be made. First, in Order No. 636, the Commission demonstrated that the current regulatory structure of the pipeline industry has, and will continue to have, a harmful impact on all segments of the natural gas industry and the Nation.[64] Second, the Commission took action to remedy that situation. The Commission expects that its remedy for the anti-competitive effects of the pipelines' bundled, city-gate, firm sales services will, as described in Order No. 636, have a significant beneficial impact on the natural gas

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62. Petition at 6 (emphasis in original). Illinois Power refers to the INGAA study showing gas supply transition costs of nearly $8 billion, Letter from Gerald V. Halverson of INGAA to Chairman Allday, dated July 1, 1991 and to Natural Gas Pipeline Company of America's April 23, 1992 filing in Docket No RP92-146 to recover at least $754.9 million of gas supply realignment costs.

63. FCC v. RCA Communications, 346 U.S. 86, 96, 97 (1953), *quoted in* Wisconsin Gas Co. v. FERC, 770 F. 2d 1140, 1158 (D.C. Cir. 1985).

64. Order No. 636 at pp. 30,398-30,406.

industry by furthering the creation of an efficient national wellhead market, which will yield an adequate and reliable supply of natural gas at reasonable prices. The Commission expects that any costs that may be incurred by the pipelines in implementing this rule will either reflect (1) costs associated with past contractual commitments which the industry was bound to face regardless of Order No. 636 or (2) short-term expenditures to restructure pipeline services so the industry can operate efficiently in the long-run.

The Commission did not rely on a paper prepared by the OEP with respect to the costs and benefits of adopting Order No. 636; that paper is not part of the record for this rulemaking and there is no reason to make it a part of the record. However, an OEP paper on this subject has been made available to the public.[65]

5. Generic Versus Individual Action

Cincinnati Gas, Tenneco, CNG, and Carnegie argue that the record does not support a generic or industry-wide response since the finding that pipeline bundled services are unlawful applies only to certain parts of the pipeline industry. Cincinnati Gas supports its contention by arguing that Table 2 in Order No. 636 overstates the percentage of sales capacity to total capacity. Table 2 indicates that percentage to be 64.1 percent. However, Cincinnati Gas maintains that the correct percentage is 39.7 percent. Cincinnati Gas adjusted the Commission's figures to account for four pipelines with no sales service which were not included in Table 2, 50 percent standby service on

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65. Costs and Benefits of the Final Restructuring Rule, Office of Economic Policy, FERC (Washington, D.C.), Spring 1992.

various pipelines,[66] and conversions subsequent to the Table 2 data.

The Commission may proceed by rulemaking or by adjudication.[67] Here, the Commission has elected to proceed by rulemaking because it views the industry-wide anticompetitive circumstance to be of sufficient breadth and complexity to necessitate industry-wide action in a timely and coordinated manner. The fact that a few pipelines have unbundled their sales and transportation services does not lessen the need to take generic action to complete the evolution of the pipeline industry as a whole to ensure there is the open access to the national gas pipeline grid needed to support the national gas market envisioned by Congress when it enacted the Decontrol Act. Cincinnati Gas' revisions to Table 2 do not undermine the Commission's analysis in that it was appropriate to exclude pipelines with unbundled services to show the magnitude of the problem in the bundled part of the pipeline industry, which is a significant number of pipelines. In addition, the 50 percent standby services should not be included as unbundled sales because the LDC can still take the bundled, city-gate, sales service and the stand-by service is not equivalent to that service. Last, even 39.7 percent is a significant ratio of sales capacity to total capacity when pipeline sales accounted for only 18.8 percent of throughput.[68] In short, under the most conservative

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66. Under 50 percent standby service, a firm sales customer may elect to receive 50 percent of its daily contract demand volumes as firm transportation service for the shipment of gas purchased from any gas suppliers.

67. Wisconsin Gas Co. v. FERC, 770 F. 2d 1140, 1166 (D.C. Cir. 1985).

68. Order No. 636 at p. 30,399, Table 2. Cincinnati Gas further states (Cont'd)

estimate, gas customers are paying for more than twice the amount of capacity than they actually need for pipeline sales services.

CNG and Carnegie also argue that the Commission has not shown that its anticompetitiveness finding applies to them. Similarly, PGT argues that there is no record evidence that would substantiate a finding of undue discrimination against PGT's present tariffs or operations, or which would justify the ban against sales by PGT at the interconnection of its facilities with those of its sales customers.

Because the Commission is determining rules of "general, prospective applicability" to solve "systemic problems of the natural gas [industry]",[69] it does not need to examine the circumstances of individual pipelines.[70] Rulemaking is the appropriate vehicle for receiving industry-wide comment and data on rules fashioned to improve the competitive structure of

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that only 6 out of the 20 pipelines on its revised table have sales contract demand volumes above 50 percent of total capacity. As a result, it claims, the disparity between reserved sales capacity and actual use is a problem that exists only in isolated pockets and does not support an industry-wide solution. Cincinnati misses the major point that the percent of capacity reserved for sales in isolation is meaningless. It is useful only when compared to the percent of capacity actually used for sales. Even on its revised table, 14 out of the 20 pipelines have a percent of capacity reserved for sales that is higher than the average of about 20 percent of throughput being used for sales. In addition, the reduced percentages result in part from the adjustment for standby service.

69. Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1166 (D.C. Cir. 1985).

70. *Id.* at p. 1165-68; Associated Gas Distributors v. FERC, 824 F.2d 981, 1008 (D.C. Cir. 1987).

open access transportation on a generic basis.[71] In Order No. 636, the Commission concluded that, in the current environment, pipeline bundled, city-gate, firm sales services on an aggregate basis are unduly discriminatory because the transportation embedded within the firm sales services is superior to firm transportation. This circumstance has an adverse impact on the efficient national interstate gas market and individualized findings are not necessary.[72] Individual circumstances are appropriately considered in the individual restructuring proceedings. Hence, this order will not consider whether certain pipelines should be excepted from any of the requirements adopted by Order No. 636 or resolve issues that are pipeline-specific rather than of a generic nature. Those matters will be considered in the individual restructuring proceedings and compliance filings.[73]

6. No-Notice Transportation

CNG and Carnegie maintain that they cannot provide a reliable no-notice transportation service. Atlanta Gas argues that the Commission should have provided record evidence to demonstrate that pipelines can perform this service. The APGA, and the Tennessee Small General Service Customers Group and the Columbia Small Customer Group (Tennessee and Columbia

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71. Wisconsin Gas Co, 770 F.2d at 1166 n. 36.

72. AGD, 824 F. 2d at 1000 n. 4 and 1008 (The Commission is not required to make individualized findings if it exercises its section 5 authority to take generic action because any tariff violating the rule would have an adverse effect on the interstate gas markets).

73. The Commission has already issued several orders exempting pipelines from Order No. 636. *E.g.*, Freeport Interstate Pipeline Co., 59 FERC ¶ 61,378 (1992).

Small Customers) object to the elimination of bundled, sales service for what they maintain is a hypothetical, theoretical, untested no-notice transportation service. Natural argues that the Commission did not engage in reasoned decision making by mandating an untried no-notice transportation service where there can be no guarantee that the new system will prove as reliable as that currently in place.

The Commission believes it is fully warranted in its prediction that the pipelines can provide a reliable no-notice transportation service. The pipelines themselves individually, and through INGAA, their trade association, provided the evidence at the January 22, 1992 technical conference, that pipelines can provide no-notice transportation service.[74] This is further attested to by INGAA's statement that "INGAA believes that the pipeline and its customers can design a no-notice transportation service to provide customers with the same degree of reliability as previously available from a pipeline's bundled merchant service."[75] The Commission sees no rational basis why, as stated by INGAA, pipelines cannot perform a no-notice transportation service. They provided no-notice service as part of their bundled, city-gate, firm sales service. The changing of the place of sale and, in some instances, the identity of the seller of the gas, should not change the ability of pipelines to deliver the gas on a no-notice basis. Thus, the concerns about no-notice transportation are unsupported and premature.[76] The parties should first address the no-notice transportation mechanics in their restructuring proceedings before a pipeline argues that it

74. Technical Conference Tr. 36-38.

75. INGAA's Petition at 10.

76. *Cf.* Northern Indiana Public Service Company v. FERC, No. 90-1528, (D.C. Cir., Jan. 21, 1992).

is impossible to provide a no-notice transportation service.[77]

7. Different Remedy

Cincinnati Gas suggests that the Commission could have selected a less intrusive remedy by mandating that pipelines implement 100 percent standby transportation service within firm sales entitlement levels.

The Commission believes that Cincinnati Gas' suggested remedy would not be in the public interest. Retaining the bundled, city-gate, firm sales service would mean that other gas sellers would not be competing with the pipeline on an even basis because they could not offer the same sales services on the same basis. For example, the pipeline could make sales at the city-gate while other gas sellers would have to sell at the production area. Even assuming that the standby transportation is no-notice transportation, the pipeline will still have the natural incentive to favor itself in managing the pipeline system. A major purpose of the Commission in adopting Order No. 636 is to design rules to counter that economic incentive to discriminate in favor of a pipeline's own bundled sales service.[78]

Moreover, the implementation of 100 percent standby transportation service would continue the problems that Order No. 636 identified and sought to correct. That is, pipelines would remain liable to provide firm sales service and keep under contract the gas necessary to provide the service, even though the customer is taking the gas from the pipeline only at peak. This would tie up reserves and lead to higher prices and increased

77. See *infra* for a discussion of "no-notice" transportation.

78. *Cf.* Tenneco Gas v. FERC, *supra*, slip. op. at 27-28, discussing the pipeline's "obvious incentive to favor its own marketing affiliate."

pipeline exposure to take-or-pay liability. It is more efficient to unbundle pipeline sales and capacity so that the pipeline can know exactly what are its obligations to its sales customers, maintain the necessary gas supply portfolio to meet those obligations, and fashion its sales rates accordingly.

8. Reliance on the Decontrol Act

Indiana Gas Company, Inc. (Indiana Gas), Tenneco, and Arkla argue that the Commission improperly relied on the Decontrol Act to support its decision to unbundle sales and transportation services. For example, Arkla argues that the Decontrol Act did not change the NGA, did no more than eliminate wellhead price controls on the first sale of natural gas, and does not support the Commission's drastic changes to the present pipeline regulatory structure. Indiana Gas adds that the generalized legislative intent of the Decontrol Act does not support the radical restructuring of Order No. 636.

The Commission recognizes that its mission under the NGA to protect consumers was not changed by the Decontrol Act. Indeed, as the Commission stated in Order No. 636, "[t]he Decontrol Act did not . . . alter the NGA's consumer protection mandate."[79] The Commission cited the legislative background to the Decontrol Act merely to show Congressional intent that the Commission act in accordance with the competitive conditions recognized by Congress in enacting the Decontrol Act, and not as evidence of a new statutory mandate. Indeed, the House Committee Report stated that the Commission's "current competitive 'open-access' pipeline system [should be] maintained" and further described the importance of open-access transportation as follows:

79. Order No. 636 at p. 30,3097.

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> The Committee stresses that these new rules, and especially the wide adoption of blanket certificates for nondiscriminatory open-access interstate transportation of nonpipeline gas, are essential to its decision to complete the decontrol process. All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest selling producer, and obtain shipment of its gas to them on even terms with other supplies.[80]

The House Committee Report further urged the Commission "to retain and improve this competitive structure in order to maximize the benefits of decontrol."[81] The Commission exercised its NGA consumer protection mandate by "seek[ing] to guarantee that the competitive conditions that now obtain in the 'wellhead' or gas-production market will redound to the benefit of the gas consumers."[82] The Commission did this by fashioning an open access transportation network where all gas sellers have equal access to that regulated essential service to ensure efficient competition in the gas sales market.[83]

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80. H.R. Rep. No. 29, 101st Cong., 1st Sess., at p. 6.

81. *Id.*

82. Panhandle Eastern Pipe Line Co., 890 F.2d 435, 436 (D.C. Cir. 1989).

83. *Cf.* Tenneco Gas v. FERC, *supra*, slip. op. at 28, quoting the Department of Justice on the adverse impact on pipeline competitors for gas sales of a lower quality of access to transportation.

Appendix C

IV. UNBUNDLING

A. Pipeline Access to Capacity

In Order No. 636, the Commission concluded that pipelines must unbundle the sales and transportation components of their bundled, city-gate, firm sales service. On the effective date of the pipeline's Order No. 636 compliance filing, each bundled sales customer's firm sales entitlement will be converted to an equivalent amount of unbundled firm sales service and to an equivalent amount of unbundled firm transportation service,[84] except as adjusted in the pipeline's restructuring proceeding. In addition, the pipeline must provide access to downstream storage and may retain downstream storage only for system management and balancing and no-notice transportation purposes.[85] Furthermore, downstream pipelines must make available capacity they hold on upstream pipelines to the downstream pipeline's customers, if requested.[86]

Several petitioners argue that the pipelines should be allowed to retain or obtain capacity rights so that they can compete on an equal basis with other gas sellers who can obtain capacity.[87] For example, INGAA argues that "[o]nce a pipeline has fully unbundled, its merchant division should be able to

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84. Conversions and adjustments are discussed *infra*.

85. Storage is discussed *infra*.

86. Upstream Capacity rights are discussed *infra*.

87. *E.g.*, INGAA, Natural, Marathon Oil Company (Marathon), Tenneco, KN Energy, Inc. (KN), ANR, Texas Gas Transmission Corporation (Texas Gas), and Questar Pipeline Company (Questar).

contract for uncommitted capacity, take assignment of capacity under the capacity releasing programs and gain access to the no-notice service not subscribed by LDCs, as long as the pipeline honors the terms and conditions of service quality."[88] Natural is concerned that it cannot make city-gate sales, which puts it at a disadvantage *vis a vis* other marketers in providing a gas delivery service using rebundled transportation and storage.

The Commission concludes that a pipeline cannot retain or obtain capacity downstream of the point of unbundling on its system except for storage as needed for system management and balancing and no-notice transportation purposes. More importantly, pipelines will be able to make sales in competition with other gas sellers. Assume that a pipeline has uncommitted capacity. Assume further that a gas customer wants to purchase gas from the pipeline. The pipeline then enters into an unbundled gas sales contract with its new customer, and a separate transportation agreement to ship the gas. In addition, the pipeline may act as the gas purchaser's agent and make all arrangements necessary for transportation of the gas. In this manner, the pipeline can compete, while maintaining the competitive and economic benefits that unbundling brings to the market place. And while it is true that their competitors can obtain such capacity either from the pipeline directly or via the capacity releasing mechanism, the Commission believes that on balance any advantage on a generic basis for those competitors will be minimal and does not warrant permitting pipelines to be capacity holders and gain the opportunity to favor themselves as gas sellers in the management of pipeline transportation facilities, including storage.[89]

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88. Petition at 10.

89. *Cf.* Tenneco Gas v. FERC, *supra*, *slip*. op. at 17, 18, 27, 28 for a (Cont'd)

B. Agency

In Order No. 636 the Commission held that a pipeline or any other merchant may act as the gas purchaser's agent in making all arrangements necessary for the gas to be transported and delivered to the gas purchaser. Order No. 636 also provides that a pipeline acting as agent may receive a negotiated agency fee as part of its unregulated sales service and must act on a nondiscriminatory basis.

Texas Gas asks the Commission to clarify that the pipeline merchant when it acts as a customer's agent in packaging pipeline services may repackage the unbundled sales and unbundled transportation by contract in such a manner that the actual title transfer is at a pooling point or market center, even if the point is downstream of the initial point of unbundling where the transportation service was separated from the sales service. Texas Gas adds that the unbundled transportation service would continue to be provided on a non-discriminatory basis originating at the point of unbundling and that the pipeline merchant service, as agent, would simply be permitted to act in a fashion similar to other merchants aggregating supplies.

The Commission denies Texas Gas' request for clarification. It is not clear why Texas Gas needs to retain title to its gas beyond the point of unbundling. First, all agents (including the pipeline and other gas sellers) act on behalf of their principal, the gas purchaser. It is the principal that holds title to the gas and holds the right to use the pipeline capacity. Hence, all agents are similarly situated. With respect to aggregating supplies, the

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discussion of the pipeline's "obvious incentive to favor its own marketing affiliate" (at 27).

parties to a particular pipeline's restructuring proceeding may consider and agree to "paper" pooling areas near the production area for the purposes of aggregation and balancing and the determination of penalties for all sellers of gas, including the pipeline.[90] In addition, a pipeline's marketing affiliate could obtain capacity and retain title to gas in the same manner as nonaffiliated gas sellers, subject to Order No. 497's standards of conduct and reporting requirements.[91]

ANR asks for clarification that the non-discrimination standard would not preclude the negotiation of different levels of agency fees, and that there would be no limitation as to the operating division of the pipeline which would be able to act in an agency capacity.

The Commission provided in Order No. 636 that the pipeline can act as an agent as part of its unbundled sales service.[92] In addition, the Commission concluded that the pipeline's fee, if any, was a matter for negotiation between it and the gas purchaser on entering into their sales contract, and that the fee would be received as part of the price for selling gas and not as part of the transportation rate. Last, the Commission stated that the pipeline

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90. At a paper pooling point, title to the gas may transfer to multiple purchasers from one seller even though there are no interconnections with other pipelines at that point. No penalties are assessed to any of the purchasers as long as their aggregate scheduled volumes equal the aggregate volumes transferred at the point from the seller to the multiple purchasers.

91. *See*, n.3, *supra*.

92. 18 CFR 284.284(d) ("A pipeline that provides unbundled sales service under this section may serve as an agent of the sales customer to arrange for any pipeline-provided service necessary to deliver their gas to the customer.")

must act in a non-discriminatory manner in offering agency services.

The Commission clarifies that the pipeline may not discriminate in providing the agency service but that the fee amount is a matter for negotiation. The Commission further clarifies that the pipeline's sales division must provide the agency service. This will ensure that all gas sellers compete on an even basis in connection with the providing of agency services. If a pipeline has no formal sales division, the agency service must be provided by its sales operating employees as an operational unit.[93]

C. Small Customer Service

In Order No. 636, the Commission did not adopt the NOPR's proposal to continue a bundled, city-gate, firm sales service for small customers. The Commission stated that those customers can be served reliably through a combination of unbundled sales, the no-notice transportation service, and the use of the pipeline or some other gas seller as the gas purchaser's agent to make all the arrangements necessary to deliver the gas to the small customer in the same manner as under the bundled, city-gate, firm sales service. In addition, the Commission stated that the small customers could continue to receive firm transportation under a one-part volumetric rate computed at an imputed load factor similar to the manner in which their current sales rates are determined.

APGA, the State of Louisiana, City Gas Company (City Gas), and the Tennessee and Columbia Small Customers argue

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93. See 18 CFR 284.286.

that the Commission erred in failing to exempt small customers from mandatory unbundling. They maintain that small customers do not have the ability to operate in an unbundled environment to secure their former reliable service at a reasonable, negotiated rate. They are concerned about maintaining service without any supply disruptions and about their disadvantage in bargaining for just and reasonable gas prices.

The Tennessee and Columbia Small Customers also argue that the Commission gave no reason why the continuation of bundled sales service for small customers would interfere in a material way with implementation of Order No. 636.

As discussed below, the Commission is sympathetic to the concerns raised by small customers. The Commission will make several changes to Order No. 636 to address those concerns. As a result, the Commission does not think it is necessary to grant rehearing as to the request to make an exception to unbundling for small customers but will grant rehearing to make other adjustments for small customers (as discussed, *infra*). The Commission does not grant rehearing on this point for several reasons. First, the Commission believes that there should be no exceptions to unbundling. As stated earlier, an exception would mean that all gas sellers would not be competing on an even basis by offering the same sales services in the same production area market. Second, an exception is not needed for small customers because they can be served reliably through a combination of unbundled sales, no-notice transportation, and agency services. Those services will enable the small customers to receive gas when needed to serve their customers on a reliable and timely basis (see *infra* on no-notice transportation service). In addition, the competitive sales market will keep the prices reasonable for gas and agency services of both pipeline and non-pipelines gas merchants. Should the small customers believe

that the pipeline prices are not reasonable, because of the exercise of market power, they may seek appropriate relief from the Commission.

Moreover, as discussed below, the Commission is adopting a one-year transitional period (from the effective date of the pipeline's blanket certificate) with respect to pipeline gas prices for small customers only.[94] During that period, the Commission is requiring pipelines, under their blanket sales certificates granted by Order No. 636, to sell gas to those customers that elect to purchase gas from the pipeline at rates that are cost-based. The Commission is doing this in order to give small customers adequate time to make alternate supply arrangements. For example, they may need more time to arrange to aggregate their gas purchases from different suppliers. As discussed below, the Commission will monitor those rates under the blanket sales certificates.[95] And, the Commission recognizes those customers' unique status by requiring pipelines to provide this cost-based service only for the small customers.

City Gas asks the Commission to clarify that pipelines will be required to compute small customer transportation rates on a one-part volumetric basis at the imputed load factor underlying the pipeline's currently effective small customer sales rate. The Commission is granting rehearing to require pipelines that, on May 18, 1992, offered a small customer sales or transportation service on a one-part volumetric basis at an imputed load factor to offer all its firm transportation services, including no-notice transportation, on the same basis, including the same eligibility

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94. This one year transition period will effectively give small customers two years to plan and adjust to their new responsibilities under Order No. 636.

95. Issues with respect to pregranted abandonment are discussed infra.

criteria, to small customers. In addition, the Commission is requiring those pipelines to consider in the restructuring proceedings enlarging the size of the small customer class from its existing size up to 10,000 Mcf or Dth/day. In the Commission's judgment, this will continue to protect the small customers. But the Commission will not give them a special marketing advantage. Therefore, the Commission will preclude the small customer from shipping gas under available interruptible transportation service on the pipeline or from shipping gas as a replacement shipper under the capacity releasing mechanism before it exhausts its firm entitlement to service under a small customer rate schedule.[96] The pipeline's tariff cannot be any more restrictive than the restrictions specified in this Order. The rates revised as part of the compliance filing must continue to maintain existing small customer classes as part of the transportation rates. The rate for the small customer class must be computed using a load factor no less than the load factor used to compute the existing small customer rate (see rate discussion *infra*) because the Commission did not direct the elimination of those rate differentials in Order No. 636.

V. OPEN ACCESS TRANSPORTATION RULES

This Part addresses the rehearing and clarification requests with respect to the essential aspects of, and terms and conditions for, open access transportation.

A. Transportation Equality

Order No. 636 adopted new regulations §§ 284.8(b)(2) and 284.9(b)(2) to require an open-access pipeline that offers firm

96. These conditions are explained below in the Transportation Rates section.

and interruptible service to provide those services on a basis that is equal in quality for all gas supplies, whether purchased from the pipeline or elsewhere. While Order No. 636 did not adopt a uniform code of terms and conditions of service, it did codify two general principles in the regulations and did state that a pipeline must have tariff provisions governing, at least, certain named transportation matters. This part V.A.addresses issues raised with respect to terms and conditions of service.[97]

1. Current Contracts

INGAA asks the Commission to clarify that pipelines can renegotiate with current shippers in order to establish operating terms and conditions and to reflect the new competitive situation. The Commission clarifies that pipelines can, subject to Commission approval in the restructuring proceedings, propose and renegotiate changes to their operating terms and conditions which are related to complying with Order No. 636.

2. Definition of Capacity

Peoples Gas System, Inc. (Peoples Gas) argues that the pipelines must be required to define "capacity" as an operating term in their tariffs so that the parties to the restructuring proceeding have an empirical definition. While the amount of capacity available is important in allocating capacity among shippers, the Commission will not require a definition of capacity in pipeline tariffs. Issues involving the amount of capacity are pipeline-specific matters that will vary by pipeline and by season. Of course, capacity must be decided in light of generally accepted engineering standards. The Commission will require the pipelines to address this issue in the restructuring proceedings.

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97. Flexible receipt and delivery point issues are discussed, *infra*.

Appendix C

3. Imbalances Penalties

Destec Energy, Inc. (Destec) asks the Commission to state that to the extent a pipeline has positive and negative imbalances existing simultaneously on its system, that such imbalances should be netted out, for penalty purposes, on a pro rata basis with imbalance penalties imposed only upon those shippers who remain out of balance after such netting out.[98] The Fuel Managers Association makes the same netting out argument: "If the pipeline experiences an excessive net imbalance during a month, only those customers that accrue an excessive monthly imbalance of a similar nature as the pipeline's excessive net imbalance, *i.e.*, a positive or negative imbalance, should be penalized for their monthly imbalances."[99]

Without reaching the merits of this particular argument, the Commission observes that penalties are a matter to be resolved in the restructuring proceedings and not for generic action. The pipelines' penalties are, of course, subject to the equality principle.

The Industrial Groups[100] argue that with the adoption of SFV for rate design, pipelines should not be able to retain penalty or cashout revenues that would enable them to profit more from penalties than from throughput. The Commission sees no

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98. The American Paper Institute, Inc. (American Paper Institute) makes the same argument.

99. Petition at 24.

100. Process Gas Consumers Group, American Iron and Steel Institute, Georgia Industrial Group, Association of Businesses Advocating Tariff Equity, California Industrial Group, California Manufactures Association, and California League of Food Processors.

relationship between SFV and penalties, which are designed to inhibit action that is inimical to the operational integrity of a pipeline system.

Consolidated Edison Company of New York, Inc. (ConEd) is concerned about multiple pipeline imbalance penalties for pipeline to pipeline deliveries where it delivers its scheduled amount into the first pipeline and takes that amount from the last pipeline but intermediate deliveries are over that amount. It argues that pipelines participating in those interactions should bear the responsibility for deliveries from pipeline to pipeline and suggests that the Commission require pipelines to establish in their tariffs scheduling and balancing procedures for multiple pipeline interactions.

Without ruling on the merits of ConEd's argument, the Commission concludes that this is a matter for the restructuring proceedings and not for generic action. The Commission observes, however, that this appears to be a matter between the upstream pipeline and its shipper about the extent of the former's liability for downstream penalties.

4. Interconnection Priority

Amoco Production Company (Amoco) argues that it is necessary to require that a shipper's type of transportation on a downstream pipeline should control access to the downstream pipeline without regard to the type of transportation used on the upstream pipeline.[101] It states that "this principle should be

101. It provides this example: "if interruptible transportation feeds downstream firm transportation, the priority at the interconnect point would be superior to other interruptible transportation at that point. If firm transportation feeds downstream interruptible transportation, the priority at

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applicable to gathering feeding mainline transportation, to upstream pipeline arrangements interconnecting with downstream pipelines, and to upstream arrangements with one shipper feeding downstream arrangements to another shipper all on the same pipeline."[102]

Brymore Energy, Inc. (Brymore) sets out an elaborate statement of priorities and asks the Commission to either order its suggested priorities to be implemented on all interconnects with interstate pipelines, or, in the alternative, to call a technical conference to establish such priorities.[103]

The Commission will not, as part of this generic rulemaking, mandate interconnection priorities. Those priorities involve terms and conditions of service. As such, they must be developed and established according to the equality principle that pipelines must provide their services on a basis that is equal in quality for all gas supplies transported under that service. However, the details of the terms and conditions of service are matters that must be addressed in the restructuring proceedings.

5. Upstream/Downstream Fuel

ConEd is also concerned about upstream and downstream

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the interconnect point would be inferior to other firm transportation at that point." Petition at 3.

102. *Id.*

103. Brymore's priorities include both scheduling and curtailment and it set forth priorities for interconnections between interstate pipelines and LDCs' interstate pipelines and non jurisdictional supply facilities and interstate pipelines.

fuel requirements and their impact on contract quantities. It believes it should be able to adjust contract quantities to reflect changed fuel requirements in order to maintain city-gate quantity levels. It suggests that pipeline tariffs and service agreements should provide firm customers with the right to adjust contract quantities to correspond to changes in upstream and downstream fuel requirements, that such changes should not be treated as part of the pipeline's transportation queue for service, and that the design of pipeline facilities should take such flexibility into consideration.

Without reaching the merits of this argument, the Commission concludes that fuel requirement issues are matters that must be considered in the restructuring proceedings.

6. Multiple Pipeline Gas Quality Specifications

ConEd is also concerned about pipeline gas quality specifications. It states that in multiple pipeline transportation "pipelines are best positioned to resolve differences in quality specifications and in quality levels at pipeline interconnects."[104] It states that "upstream pipelines engaging in multiple pipeline interactions must assume the responsibility of delivering to the downstream pipeline gas which meets the quality specifications contained in the downstream pipeline's tariff [and] . . . pipelines agreeing to provide downstream service must agree not to unilaterally change their quality specifications where such changes would be inconsistent with the quality specifications of the upstream pipeline and would thereby result in rejection of gas tendered."[105]

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104. Petition at 7.

105. *Id.* at 7, 8.

The Commission concludes that gas quality specification issues are matters that must be considered in the restructuring proceedings.

7. First-Come/First Served Queue

Tejas Power Corporation (Tejas) argues that existing first-come, first-served queues for firm or interruptible transportation queues should be abolished in conformity with the Commission's right of first refusal mechanisms, which are designed to allocate capacity to customers who value it the most. Tejas recommends replacing the first-come, first-serve queue with a "system of bidding for priority of service" or "at a minimum . . . the formation of new queue on a regular basis after implementation of the Rule."[106] It adds this is especially important for interruptible queues.

Northern Indiana Public Service Company (Northern Indiana) argues that interruptible service priority rights based on queue dates must be eliminated. It maintains that the grandfathered queue dates will give certain shippers power over capacity, leaves the door open to unregulated capacity brokering and buy/sell arrangements, and could discourage new entrants into the gas market. It argues that if the Commission does not abolish queue date priorities, it must require pipelines to publish existing queue lists for interruptible transportation and storage services along with a utilization history.

Without reaching the merits of Tejas' or Northern Indiana's arguments, the Commission will not address prematurely here any queue issues as they relate to capacity obtained from the pipeline. The Commission notes that the pipelines *must* post

106. Petition at 10.

available firm and interruptible capacity on their electronic bulletin boards so that potential shippers may choose between pipeline and released capacity. How the pipelines allocate their own capacity among multiple aspirants for that capacity is an issue that must be considered in the restructuring proceedings. If a dispute arises during the restructuring discussion that cannot be resolved by the parties, the Commission will resolve those disputes when the pipeline makes its scheduled compliance filing, or earlier, if brought before the Commission. The Commission further notes that mandatory implementation of capacity release mechanisms on the pipelines may affect queues because released capacity will be a significant alternative transportation option for acquiring transportation capacity.

8. Security of Service

Brooklyn Union Gas Company (Brooklyn Union), *et al.*[107] argue that "security of service" issues must be addressed by the Commission, that is, the "pipeline [must] be responsible for redelivery at the city gate of quantities of gas equivalent to those delivered into the pipeline by or for, each firm transportation shipper, even in the event of overruns by other shippers."[108] They state that the pipeline must use or impose tools to discipline the system, for example, "the installation of real time metering equipment, the development of predetermined allocation procedures, and the availability of dispatchers on a twenty-four hour basis" and "meaningful [overrun] penalty charges."[109]

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107. ConEd and Public Service Electric and Gas Company (PSE&G).

108. Petition at 7.

109. *Id.* at 7 n. 7 and 8.

The Commission agrees with Brooklyn Union, *et. al.*, that, as a general matter, pipelines are responsible for delivering to shippers the amount of gas injected into the pipeline. These issues involving this responsibility, such as exceptions and disciplinary tools, must be considered as part of the restructuring proceedings.[110]

B. Electronic Bulletin Boards

Order No. 636 requires pipelines to provide timely and equal access to all information necessary for buyers and sellers to arrange for capacity reallocation and requires this information to be provided on electronic bulletin boards (EBB). American Paper Institute, Brymore, ConEd, Industrial Groups, Kern River Pipeline Co. (Kern River), Mobil Natural Gas Co. (Mobil), Natural Gas Clearinghouse, Natural Gas Supply Association/ Indicated Producers (NGSA), New Jersey Natural Gas Co. (New Jersey Natural), PSE&G, and UGI Utilities (UGI) seek rehearing or clarification of the requirements for EBBs.

Several petitioners[111] argue that the Commission erred in failing to adopt uniform national standards for EBBs. These parties assert that uniform standards are necessary to eliminate inefficiencies and promote development of market centers. They assert that without standardization of interfaces and formats, access to many EBBs will be very costly. Brymore Energy asks the Commission to establish a Task Force to act as a catalyst in

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110. The Commission rejects Cincinnati Gas' request that the Commission impose a Uniform Gas Day, because the Commission has no jurisdiction over most production area gas sales.

111. American Paper Institute, Brymore, Natural Gas Clearinghouse, NGSA, and New Jersey Natural.

the process of developing standards, and Natural Gas Clearinghouse asks the Commission to establish a technical conference for this purpose.

During the past year, the Commission's staff has been auditing the performance of and access to pipeline EBBs. Based upon that information, the Commission agrees that standardization of information content, display formats, and software is extremely important and would greatly enhance the efficiency of the capacity release program to the benefit all users of the pipeline system. The Commission believes that the lack of uniform standards can hamper efficient movement of gas across pipelines and can inhibit the development of market centers. The Commission, however, does not have sufficient information at this time to prescribe and mandate uniform standards beyond those contained in Order No. 636. The Commission strongly encourages the industry to develop its own uniform standards and conventions for use of EBBs without Commission intervention. Although the Commission will not initiate a generic proceeding to address appropriate uniform standards at this time, the Commission will hold a technical conference in the near future in order to determine the progress made by the industry in developing interactive, user-friendly EBBs and uniform standards.

American Paper Institute, ConEd, Mobil and NGSA ask the Commission to require the pipeline to include the terms and conditions for access to EBBs in their tariff filings. These parties assert that access agreements are often one-sided and the Commission should review the pipelines' tariffs to assure that they are reasonable and non-discriminatory.

The Commission agrees. The terms and conditions of access

to EBBs must be just and reasonable and must be included in the pipeline's tariff. The Commission directs the pipelines to include these provisions in the compliance filings.

American Paper Institute asks the Commission to clarify the EBBs must be operational and meet the Commission's criteria no later than the effective date of the pipeline's tariff filing implementing Order No. 636. Rochester Gas & Electric (Rochester Gas) asserts that the EBBs must be operational as soon as possible, even before the pipeline is in compliance with Order No. 636.

In some cases, pipelines may implement capacity releasing prior to implementing the remainder of the restructuring requirements.[112] The Commission clarifies that the appropriate date for EBBs to go on-line is no later than the effective date of the tariff sheets implementing the capacity releasing mechanism.

The standards of conduct adopted in this rule require that to the maximum extent practicable, the pipeline's transportation employees and its gas marketing employees must function independently of each other.[113] The EBB is part of the transportation function and, thus, the regulations already require that the EBB personnel function independently of the gas marketing personnel to the maximum extent practicable. Because the EBB is an integral part of the transportation operation, further separation is not feasible.

Rochester Gas raises the issue of the proprietary nature of

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112. Northern Natural Gas Co., 59 FERC ¶ 61,362 (1992); Northern Border Pipeline Co., 59 FERC ¶ 61,312 (1992).

113. 18 CFR 284.286.

EBB information by stating that it assumes pipelines will permit anyone to access, download, and disseminate data from the EBBs. The Commission clarifies that it does not consider the information that must be on the EBB to be proprietary.

Mobil argues that the EBBs should be interactive, and that a potential capacity buyer should be able to respond to the offer and close the deal on the EBB without intervention of the pipeline. The Commission believes that interactive EBBs will enhance the efficiency of the system and, therefore, directs pipelines to provide for interactive bulletin boards if feasible on the particular system. A pipeline must explain in the restructuring proceeding why it believes that an interactive EBB is not appropriate on its system.

Kern River asks the Commission to clarify that historical information does not have to be accessed on the bulletin board, but can be maintained off-line. The request for clarification is granted. Historical data does not have to be accessed on the EBB. As the Commission stated in Order No. 636, the pipeline must keep daily back-up records of the information displayed on their EBB for at least three years, and should permit users to review those records, which should be reasonably accessible.[114] In addition, Order No. 636 provides that pipelines must periodically purge completed transactions from current files so that EBB users do not have to sift through massive amounts of historical data to find current information.[115] Archived information should be available for a reasonable fee in electronic form. Pipelines are directed to include procedures for back-up, archiving, and retrieval in their tariffs.

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114. Order No. 636 at 68.

115. *Id.*

Appendix C

C. Capacity Reallocation

In Order No. 636, the Commission adopted, in new sections 284.242 and 284.243, two new capacity reallocation programs. The Commission announced that it will not approve new individually authorized capacity brokering and other capacity assignment mechanisms. The Commission, in a separate order issued April 8, 1992, amended the terms and conditions of existing capacity brokering and other assignment programs to conform to the capacity reallocation regulations adopted in Order No. 636.[116] However, the Commission allowed capacity assignments and reassignments in effect on the effective date of a pipeline's capacity reallocation mechanism to continue in effect, provided the original capacity holder retains its capacity through the restructuring proceeding mechanism. In addition, all capacity assignments must be done under the new mechanisms once they become effective. This includes buy/sell arrangements where an LDC purchases gas in the production area from an end user or merchant designated by an end user, ships the gas on its (the LDC's) own capacity, and sells the gas to the end user at the retail delivery point.[117] The Commission, however, permitted buy/sell arrangements in effect on the effective date of a pipeline's capacity reallocation program to continue in effect provided the LDC retains its capacity through the restructuring mechanism. In addition, the Commission required that the pipeline post particulars of the buy/sell deals on its electronic bulletin board to make those transactions public.

As a general matter, the Commission denies rehearing on these issues. However, the Commission will make several

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116. Algonquin Gas Transmission Co., 59 FERC ¶ 61,032 (1992).

117. El Paso Natural Gas Co., 59 FERC ¶ 61,031 (1992).

changes on rehearing to the capacity assignment mechanisms. The most significant change is that shippers can release capacity for any period of less than one calendar month without prior posting on the EBB or bidding for the released capacity. Those releases must be announced on the EBB as soon as possible after the transaction commences, but no later than forty-eight hours,[118] and no roll-overs or extensions will be permitted without prior notice and opportunity to bid for the capacity.

1. Jurisdiction Over Capacity Brokering Activities

The Public Service Commission of the State of New York (New York PSC), Atlanta Gas, and UGI maintain that the Commission has no jurisdiction over the assignment of capacity rights by an LDC to a customer on the LDC's system because the LDC is not a jurisdictional transporter of gas. APGA contends that the Commission has no authority to require municipalities to comply with the section 284.243's capacity releasing procedures and limitations because municipalities are not subject to Commission jurisdiction under either the NGA or the NGPA.

The Commission rejects the contention that it lacks jurisdiction over the assignment of capacity by LDCs. In *Texas Eastern Transmission Corp.*,[119] the Commission resolved the jurisdiction question as follows:

> Since the brokering, or assignment, of

118. The Commission believes that forty-eight hours is an appropriate and feasible period for requiring posting unless a pipeline can demonstrate that some short extension of the maximum time is necessary for operational reasons.

119. 48 FERC ¶ 61,248 (1989), *order on reh'g*, 51 FERC ¶ 61,170 (1990).

> transportation capacity will control the access to that capacity, the Commission believes that brokering is tantamount to transportation. Therefore, brokering constitutes a new transportation service, subject to the Commission's jurisdiction, that is not covered directly by existing NGA section 7(c) transportation authorizations.[120]

The Commission amplified that analysis in the rehearing order by stating that there will be a movement of gas in interstate commerce by the assignee of capacity rights, "[B]y controlling such capacity, [the assignors] are effectively determining by whom, and under what circumstances gas will be transported" and are using the pipeline's facilities as if they were the assignors' facilities.[121] The Commission added that the NGA does not limit the Commission's jurisdiction to the actual physical transportation or delivery of natural gas and that a narrow construction of the Commission's jurisdiction would create a regulatory gap and a significant dilution of the Commission's regulatory authority over the pipelines themselves.

The Commission adheres to that analysis and conclusion that the Commission has NGA jurisdiction over the brokering or assignment of capacity by LDCs, and this is irrespective of whether the assignee is an LDC customer or, as Atlanta Gas maintains, a replacement shipper within the same state.[122]

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120. *Id.*, 48 FERC ¶ 61,248 at p. 61,873.

121. Texas Eastern Transmission Corp., 51 FERC ¶ 61,170 at p. 61,452 (footnote omitted).

122. Accordingly, contrary to the United Distribution Companies (UDC)

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The Commission also believes that petitioners have not recognized the essence of a capacity assignment. In effect, the pipeline is temporarily abandoning service to the releasing shipper and instituting service to the replacement shipper. Both of those activities are subject to the Commission's jurisdiction under NGA sections 1(b) and 7(b) and (c).

The Commission agrees with the APGA that municipalities are beyond the jurisdiction of the Commission.[123] However, this means only that municipalities need not be certificated to transport gas on their own systems[124] or to participate in jurisdictional capacity brokering or releasing mechanisms.[125] However, this does not mean that municipalities are entitled to release capacity on an interstate pipeline without complying with the procedures pertinent to the pipeline's releasing mechanism. It means only that the municipalities need not be certificated to release capacity. The Commission's clarification in *Texas Eastern Transmission Corp*, that "all the conditions imposed upon program participants do not apply to municipalities" is not applicable where the conditions pertain to the mechanics of

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(Cont'd)
and New York PSC, the Commission's issuance of a limited certificate of public convenience and necessity to firm shippers, to the extent necessary and solely for the purpose of releasing firm capacity, 18 CFR 284.243(g), was appropriate.

123. Texas Gas Transmission Corp., 55 FERC ¶ 61,208 (1991); and Texas Eastern Transmission Corp., 51 FERC ¶ 61,170 (1990). Nor are municipalities' rates and service regulated by most state Commissions.

124. Northwest Alabama Gas District, 42 FERC ¶ 61,371 (1988).

125. Texas Gas Transmission Corp., 55 FERC ¶ 61,208 at p. 61,698 (1991).

the release by and through the pipeline.[126] In that circumstance, the capacity releasing mechanism is no different from any other pipeline term or condition of service with which the municipality must comply.

2. Retention of Capacity Brokering

Several petitioners argue that the Commission should have allowed capacity brokering programs to continue[127] or, at least, grandfathered existing programs.[128]

NYSE&G argues that capacity brokering is more in tune with private contractual arrangements and is superior to prearranged deals under capacity releasing because the latter permits preemption by a "better offer," which is an "invitation to controversy."[129] The CNG LDCs argue that capacity brokering is superior because the LDCs "may temporarily broker capacity to their own end users."[130] Several petitioners argue retention of capacity brokering along side of capacity releasing will provide pipelines with the incentive to market released capacity, for example, in competition with their own interruptible

126. Texas Eastern, 51 FERC ¶ 61,170 at p. 61,454 (1990).

127. New York State Electric & Gas Corporation (NYSE&G), New Jersey Natural, CNG LDCs, Wisconsin Distributor Group, PSE&G, the Industrial Groups, and New York PSC.

128. CNG LDCs. Indiana Gas contends, without supporting argument, that "Order No. 636 should be amended to establish capacity brokering programs." Request for Rehearing at 7.

129. Petition at 7. "Best Offer" is discussed *infra*.

130. Petition at 5.

transportation.[131] New York PSC argues that capacity brokering should not be replaced because, under releasing, the pipelines are unnecessary middlemen and can underbid the LDCs to keep interruptible service. It also maintains that it is aware of no complaints against the programs on six pipelines serving New York State.

Atlanta Gas, New York PSC, UGI and CNG argue that the capacity releasing mechanism is too time consuming, too administratively complex, imposes additional transaction costs, and reduces flexibility. Hadson Gas Systems, Inc. (Hadson) similarly contends that the new capacity releasing rule will discourage the development of a secondary capacity market because the required posting of prearranged deals raises the possibility of deal stealing which will cause potential assignors to either fashion complicated, ambiguous, and confusing arrangements or just not attempt it at all.

The Commission upholds its decision not to approve new individually authorized capacity brokering and other capacity assignment certificates.[132] The Commission believes it is desirable for efficiency and administrative reasons for all allocations to be effected through the pipeline to avoid the possibility of discriminatory allocations. For example, the

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131. PSE&G and Wisconsin Distributor Group.

132. The Commission's decision to amend the terms and conditions of existing capacity brokering and other capacity assignment programs to conform to Order No. 636's capacity allocation mechanisms was effected in Algonquin Gas Transmission Co., 59 FERC ¶ 61,032 (1992). Hence, the Commission will address objections to that decision in the rehearing of that order and not here. That order will be issued contemporaneously with Order No. 636-A.

possibility exists that LDCs might favor their own end-users in ways that constitute potential undue discrimination. In addition, contrary to the rehearing contentions, the Commission believes that the two new generic capacity allocation mechanisms of sections 284.242 and 284.243 of the Commission's regulations are adequate substitutes for existing programs and will eliminate the potential for discrimination, while facilitating the development of the secondary transportation market.

The Commission believes that the mechanism for prearranged deals under the capacity releasing program will permit parties to fashion permanent or temporary capacity reallocations in a manner similar to capacity brokering. In that vein, as discussed below, the Commission is permitting releases for less than thirty days (up to 29 days) to be effected without prior posting on the EBB or bidding on the released capacity. Those releases must be announced on the EBB as soon as possible, but no later than forty-eight hours, after the transaction commences and no roll-overs or extensions are permitted without prior notice on the EBB and an opportunity to bid.

The opportunity for potential competitors to bid is appropriate because it permits someone to make a better offer and obtain the capacity. This may enable the releasing shipper to receive more revenue for its firm capacity. The posting of the prearranged deal is appropriate in order to keep all deals public so that discrimination can be detected and prevented. The pipelines are not unnecessary middlemen but perform the function of a public clearinghouse for all transactions. In addition, the EBBs should give releasing shippers exposure to more replacement shippers and pipelines will be able to combine releases to make then more marketable. The pipelines will have an adequate incentive to market released capacity because of the fee that they can receive to actively market capacity.

Moreover, as open access transporters, the pipelines must accommodate requests for service, if their own or released capacity is available. In addition, the pipelines must offer their own capacity on the EBB. The Commission views the competition between interruptible transportation and capacity releasing as part of a healthy secondary capacity market. The Commission does not believe that the lack of complaints on six pipeline systems is relevant to the devising of a generic capacity reallocation program for the entire pipeline industry.

As discussed further below, the Commission has adjusted the capacity reallocation mechanism to accommodate some of the arguments made by petitioners. However, the Commission has done that without compromising the central purpose of adopting the capacity allocation mechanism in lieu of capacity brokering — notice and oversight of the assignment of pipeline capacity. As modified, the Commission does not believe, based upon its experience with the gas industry, that capacity releasing will be too time consuming, too administratively complex, impose unreasonable costs, or unduly reduce flexibility. Rather, the Commission believes that an efficient, appropriately-priced capacity releasing mechanism can be fashioned to create an efficient, flexible, competitive, and reasonable secondary market for pipeline capacity while, at the same time, avoiding the potential for discrimination. Specific details of capacity releasing are discussed below in the section dealing with specific rehearing requests on those details.

3. Voluntary Reallocation Of Firm Transportation Capacity

Under new section 284.243, an open access pipeline must provide a capacity releasing mechanism that lets shippers voluntarily reallocate all or part of their firm transportation

capacity to any person. The capacity release mechanism would operate through the pipeline's electronic bulletin board, and the replacement shipper would contract with the pipeline for the reallocated capacity, with the releasing shipper receiving a credit for the proceeds of the release. Except when necessary to respond to petitioners' arguments below, the Commission will not repeat Order No. 636's discussion of the mechanics of capacity releasing.

a. Exceptions For Short Term Or Small Volume Transactions

Several petitioners contend that the Commission should not subject short-term (one to three months) or small volume transactions (less than 5,000 to 10,000 Dth) to the bidding requirements of the capacity release mechanism.[133] Instead, they contend the Commission should allow parties to consummate these transactions on their own, subject only to posting the deal on the pipeline's electronic bulletin board. They contend that the requirement for advance posting and bidding in Order No. 636 would be too administratively difficult for short term or low volume releases and therefore could inhibit the efficient allocation of capacity.

As a policy matter, the Commission believes that the public interest is served by fostering a robust secondary market in pipeline firm capacity. At the same time, the Commission seeks to ensure that the efficiencies of the secondary market are not frustrated by unduly discriminatory access to this market. To balance these objectives, the Commission will modify the

133. *E.g.*, United Distribution Companies, New York PSC, the Industrial Groups, Northern Distributor Group, New England Gas Distributor Group, Associated Gas Distributors (AGD), and ANR.

regulations to permit firm shippers to find their own replacement shippers and release capacity to those shippers for any period of less than one calendar month without having to comply with the bidding requirements of section 224.243. The same maximum rate would apply to these transactions as to other capacity release transactions. Releases under this exception must be posted on the electronic bulletin board as soon as possible, but no later than forty-eight hours, after the release transaction begins. Parties will be prohibited from rolling-over such agreements or granting extensions without complying with the requirements for prior notice and bidding.

The exception from the bidding requirements for short-term releases will not relieve the pipeline from its obligation to devise capacity releasing procedures facilitating short-term releases.[134] The Commission expects that, in most instances, capacity release mechanisms can be implemented which will permit releases for one day or less at any time during a month, and provide for release transactions to be finalized within twenty-four hours of posting. The Commission recognizes that meeting such goals may not immediately be achievable by all pipelines. Pipelines proposing significantly greater restrictions need to justify them and explain in their compliance filing when they will be able to adopt less restrictive conditions.

Accordingly, the Commission will modify section 224.243 to add a new paragraph (h) as follows:

(1) A release of capacity by a firm shipper

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134. Stock and commodity exchanges, for example, consummate such transactions in very short time periods and, with the availability of existing computer technology, pipelines can design workable short term releasing mechanisms.

to a replacement shipper for any period of less than one calendar month need not comply with the notification and bidding requirements of paragraphs (c) through (e) of this section. A release under this paragraph may not exceed the maximum rate. A firm release under this paragraph must be noticed on the pipeline's electronic bulletin board as soon as possible, but not later than forty-eight hours after the release transaction commences.

(2) A firm shipper may not rollover, extend, or in any way continue a release under this paragraph without complying with the requirements of paragraphs (c) through (e) of this section and may not re-release to the same replacement shipper under this paragraph until thirty days after the first release period has ended.

Given the modification for short term releases, the Commission does not find that a separate exception for low volume releases is needed. The short term modification will permit release of any amount of capacity for less than thirty days. Volumes of up to 10,000 Dth per day for more than this period may be significant and compliance with the notice and bidding requirements should not create any administrative difficulties.

b. Priority Issues

(1) Priority for Pre-Arranged Deals

The Commission in Order No. 636 established capacity releasing under section 284.243 as a nondiscriminatory vehicle for pipeline transportation customers to release capacity voluntarily on a permanent or temporary basis. In general, capacity would be released to the person offering the highest rate and offering to meet the other terms and conditions of the bid. The Commission recognized, however, that permitting parties to continue to prearrange deals for redistributing capacity would facilitate capacity reallocation. Permitting prearranged deals would provide pipeline customers with an incentive to market their unneeded capacity actively rather than simply posting the capacity on the pipeline's bulletin board. In section 284.243, the Commission therefore gave priority to prearranged deals: the replacement shipper under the prearranged deal would receive the capacity so long as it was willing to match any better offer. Several petitioners argue that the order of priority established in Order No. 636 should be modified.

Several petitioners argue that a releasing LDC should be able to designate replacement shippers without exposure to the bidding process.[135] They argue that such priority would ensure that the released capacity remains on the LDC's system, so that the LDCs would not lose revenues from the diversion of capacity to off-system markets. The Industrial Groups argue that, in the alternative, the Commission should permit releases to be conditioned on the replacement shipper using the released capacity to deliver gas to customers served by the releasing LDC.

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135. CNG LDCs, Alabama Gas Corporation (Alabama Gas), and the Industrial Groups.

Appendix C

American Paper Institute argues that existing end-use customers should have priority to released capacity if they are willing to bid the maximum rate. Peoples Natural Gas Company (Peoples Natural Gas) similarly argues that an end-user behind an LDC should have priority if it matches the price of a third party bidder even though it does not match other terms and conditions.

The Commission does not believe that revising its priority provisions for capacity release is necessary. The purposes of the capacity release provisions were twofold: first, to ensure that notice would be given for all capacity reallocations and second, to give parties an opportunity to bid a higher rate so that allocative efficiency is enhanced by allotting capacity to the shipper placing the highest value on the capacity. As discussed previously, the Commission is excepting short term releases from the bidding requirement. However, the Commission will not permit a general exception for all releases to a designated shipper. Such an exception would involve a large number of significant transactions and therefore would greatly undermine the allocative efficiency goal sought to be achieved by the bidding requirement. Elimination of the bidding requirement also is not necessary to enable LDCs and end-users to consummate beneficial deals to allocate capacity. Under the capacity release mechanism, an LDC can negotiate a prearranged deal with an end user and that end user will receive the capacity as long as it matches the best offer. Thus, an end-user under a prearranged deal meeting these conditions will be assured of receiving the capacity.

(2) Priority for Shippers on the Pipeline's Firm Queue

Brymore argues that the Commission's priority for

prearranged deals at the maximum rate is unfair to shippers that have been on a pipeline's queue for firm capacity, and that shippers on the firm queue should receive priority if they match the best bid. O & R Energy, Inc. (O & R Energy) asserts that, under certain Commission approved tariffs, parties have made transportation prepayments to hold a place in a pipeline's queue, payments which may be refundable if capacity is not available or the buyer withdraws its request. O & R Energy requests that the Commission modify section 284.243 to provide that the pipeline must first discharge its tariff obligations to potential shippers in its firm transportation queue.

The Commission does not believe shippers on a pipeline's firm queue should be accorded priority over prearranged deals. First, as pointed out above, the capacity release mechanism was not intended to prohibit prearranged deals, but to ensure that notice of all such deals was provided.[136] Second, the pipeline's queue applied only to the allocation of the pipeline's own capacity and never to released or brokered capacity. The Commission in Order No. 636 also modified the role of the firm queue by requiring that available pipeline firm capacity must be posted on the electronic bulletin board and allocated to the shipper making the best offer. In the restructuring proceedings, however, the parties should consider whether the existing firm queue or other provisions provide the best method for allocating the pipeline's available firm capacity when identically valued bids for pipeline capacity are received. The Commission will clarify that if a pipeline' firm queue is eliminated, deposits to retain position on the queue must be returned according to the terms of the pipeline's tariff.

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136. By requiring that capacity is to be awarded to the prearranged deal only when no better offer is received, the capacity release mechanism ensures that the capacity goes to the highest valued use.

Appendix C

(3) Priority for Sale of Pipeline Capacity

Order No. 636 did not adopt the NOPR's proposal that the pipeline may sell its own available firm capacity prior to reselling that of a releasing customer.[137] Instead, the pipeline must post its available firm capacity on the electronic bulletin board so that potential shippers can elect whether to purchase the pipeline's or releasing shippers' capacity. Some pipelines have requested the Commission to reinstate the provision allowing pipelines to sell unused capacity ahead of released capacity.[138] ANR and Tenneco, for example, argue that if released capacity is sold prior to pipeline capacity, the pipeline may be unable to sell its firm capacity, thereby raising transportation rates for all customers. They contend that customers unable to release capacity will therefore be paying higher rates which will subsidize customers that can release capacity.[139] CIG asks the Commission to permit pipelines to sell their interruptible capacity prior to the release of firm capacity arguing that otherwise, firm customers that cannot release capacity will not be able to mitigate the reservation fees they pay.

The Commission adheres to the requirement in Order No. 636 that pipeline capacity (firm and interruptible) must compete with released capacity. Competition between pipeline capacity and released capacity helps ensure that customers pay only the competitive price for the available capacity. Granting preferences to pipeline capacity over released capacity could interfere with

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137. Order No. 636 at p. 30,419.

138. *E.g.*, ANR, CIG, Tenneco, and Questar Pipeline Company (Questar).

139. Tenneco and ANR.

and frustrate competition and artificially raise the price of pipeline capacity to new shippers. Shippers seeking capacity should be able to select the transportation option (pipeline firm, released firm or pipeline interruptible) with the terms and price that best fits their needs. The pipelines are free to respond to releases of capacity as competition dictates, within the limits and requirements of the Commission's regulations.[140] Affording preference to pipeline capacity over released capacity also could reduce the incentive for shippers to post released capacity.

Further, the capacity release mechanism was intended to create a robust secondary market for pipeline capacity in which unneeded firm capacity would be available to shippers requiring that capacity. This allocation process should forestall the construction of unneeded new capacity, which in turn will result in lower costs for pipelines and all their firm shippers.

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140. The petitioners suggest that according pipeline capacity a preference over released capacity would result in reduced rates for all customers due to increased sale of pipeline capacity. However, any incremental sales of pipeline capacity would not affect the customers' rates in the short run. A pipeline's current rates are set in its tariff and generally are revised only when the pipeline files for new rates under section 4 of the Natural Gas Act. Thus, even if pipeline capacity was given the requested preference, the pipelines would retain the incremental revenues and would not have to reflect these revenues until an unspecified future date when the pipeline filed to raise its rates generally. In contrast, under the capacity release mechanism the releasing shipper immediately obtains a lower cost by receiving the proceeds from the release.

Appendix C

c. Terms and Conditions

(1) Determination of Best Bid

i. Should the Pipeline or Releasing Shippers Determine the Best Bid?

The Commission in Order No. 636 provided that releasing shippers can set the terms and conditions for the release of capacity and that the pipeline must allocate the released capacity to the person offering the highest rate, not over the maximum rate. Recognizing the multiplicity of releasing scenarios that could arise, the Commission determined that the parties in the restructuring proceedings should determine what constitutes the best offer.[141]

Several petitioners[142] request that the Commission clarify that the releasing shipper should be the appropriate party to determine the best offer, not the pipeline. Gas Company of New Mexico suggests that either the releasing shipper be given the ultimate decision to determine best offer or, alternatively, the choice "should be based on the total economic benefit provided to the releasing shipper." It posits that this approach would better deal with situations in which a releasing shipper may be releasing capacity on multiple pipelines. The Northern Distributor Group, Destec, and Fuel Managers Association request clarification that releasing shippers should be able to use criteria other than price

141. Order No. 636 at p. 30,418.

142. *E.g.*, United Distribution Companies, AGD, Long Island Lighting Company (LILCO), CNG LDCs, Wisconsin Distributor Group, UGI, Northern Distributor Group, the Industrial Groups, Destec, the Fuel Managers Association, Midland Cogeneration Venture (Midland Cogeneration), and the Pennsylvania Public Utility Commission (Pennsylvania PUC).

to choose replacement shippers. The Industrial Groups supports allowing releasing shippers to determine the best bid, but further argues that regardless of who decides, payment made by customers as part of their retail rates should be taken into account in determining the best bid. It argues that since customers of LDCs have been paying for pipeline capacity through their retail rates, they should not have to pay the effective maximum rate for released capacity.

On the other hand, some petitioners request that the Commission establish specific parameters for determining the best bid.[143] For instance, Spot Market Corporation of the State of Texas (Spot Market Corporation) is concerned about the operation of capacity release on the PGT system. It maintains that because PGT has a low transportation fee, every potential replacement shipper will bid the maximum amount and that a screen of factors must be used to establish priority.

The Commission will clarify its position with respect to terms and conditions and best bids. Due to the variety of releasing conditions that may exist, the Commission will not establish only one methodology for evaluating best bids, but will use the following approach.

The pipeline's tariff must include an objective and non-discriminatory economic standard for determining best bids. Releasing shippers may rely upon this standard in structuring their capacity releases, but are not required to do so. If a releasing

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143. National Independent Energy Producers (NIEP)(recommending objective generic standards such as net present value, first-come/first-served, or pro-rationing, but also giving weight to the opinion of the releasing shipper); Brymore (all other things being equal, *e.g.*, rate and term, the shipper guaranteeing the highest load factor usage should receive capacity).

shipper does not specify a standard, the standard in the pipeline's tariff will apply.

Releasing shippers may include in their offers to release capacity reasonable and non-discriminatory terms and conditions to accommodate individual release situations, including provisions for evaluating bids. All such terms and conditions applicable to the release must be posted on the pipeline's electronic bulletin board and must be objectively stated, applicable to all potential bidders, and non-discriminatory. For example, the terms and conditions could not favor one set of buyers, such as end users of an LDC, or grant price preferences or credits to certain buyers. The pipeline's tariff also must require that all terms and conditions included in offers to release capacity be objectively stated, applicable to all potential bidders, and non-discriminatory.

ii. Pooling and Aggregating Capacity

NIEP argues that the Commission's capacity release mechanism should permit pooling arrangements under which a replacement shipper obtains a pool of capacity rights on different pipelines from an LDC. The replacement shipper can use capacity from each pipeline and pays the LDC a weighted average price for the entire pool.

Based on NIEP's description, the average price term may in some instances appear to conflict with the regulations providing that the rate for released capacity cannot exceed a pipeline's maximum rate. As NIEP recognizes, the average price will be higher than the maximum rate on at least one pipeline. However, within the constraints of the regulations, the Commission intends for its capacity releasing program to be as flexible as possible in order to promote efficient releases. A

pooling arrangement, such as the one NIEP describes, potentially could be accomplished depending upon how the transaction is structured.

The APGA and Municipal Gas Authority of Georgia request that the Commission clarify that it will permit a program where firm capacity holders aggregate their unused firm capacity for release by the pipeline. They propose that the pipeline receive a commission of ten percent of all revenues, with the remainder credited to the firm capacity holders in proportion to the amounts of unutilized firm capacity that they made available.

The Commission finds nothing in the regulations promulgated by Order No. 636 that would prevent firm capacity holders from aggregating firm capacity on the same or different pipelines to enhance its marketability for release.[144] If more than one shipper is aggregating capacity, the shippers involved would have to determine among themselves how to allocate the credit from the release. The Commission further clarifies that the pipeline would be eligible to receive a negotiated marketing fee only if it actively markets the capacity.

iii. Length of Contract

American Paper Institute contends that the length of contract should not be taken into account in determining bid value,

144. In Order No. 636, the Commission gave an example of a shipper holding capacity from the Gulf of Mexico to New York being able to release its capacity between those points at up to the maximum rate for the path from the Gulf to New York. Order No. 636 at pp. 30,420-21. Similarly, a shipper holding capacity on an upstream and downstream pipeline, which together provide a path from the Gulf to New York, could aggregate that capacity for a single release. Each block of capacity could be sold at up to the maximum rate on each pipeline and the transaction would have to be posted on each pipeline's electronic bulletin board.

because not all gas users can commit to long term contracts. The Commission will not eliminate length of contract from the determination of best bid since a releasing shipper may consider contract duration to be an important consideration in releasing capacity.

(2) Creditworthiness

Several petitioners contend that the releasing party should have the right to condition its release on the replacement shipper demonstrating its creditworthiness or paying an amount in advance.[145] Because the replacement shipper is contracting with the pipeline for released capacity, it must satisfy all the pipeline's tariff provisions governing eligibility.[146] In the pipeline's restructuring proceedings, however, the pipelines need to develop tariff procedures to effectuate and expedite the capacity releasing mechanism. For example, pipelines may develop tariff provisions permitting bidders to pre-qualify under their eligibility standards.

(3) Peak Day Restrictions

Northern Illinois Gas Company (Northern Illinois Gas), *et al.*[147] is concerned about its ability to ensure that it has adequate gas volume flowing into its system on peak days. To deal with this problem, it asserts that, although replacement shippers generally should be able to make use of flexible delivery points,

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145. *E.g.* LILCO and New England Gas Distributors.

146. Order No. 636 at p. 30,419.

147. Peoples Gas Light and Coke Company, and North Shore Gas Company.

a releasing shipper should be able to restrict the replacement shipper's use of released capacity to primary delivery points either generally or in certain demand conditions. The Commission is not sure how restricting replacement shippers to primary delivery points would promote adequate gas flows on peak days since the gas flowing would be that of the replacement shipper. However, the Commission clarifies that a releasing shipper may include terms and conditions, such as recall rights, that will ensure it has adequate peak day transportation.[148] The Commission also notes that a party holding capacity to a primary delivery point always will have priority over a firm shipper using that delivery point as a secondary delivery point on an interruptible basis.

(4) Minimum Price

Western Resources, Inc. (Western Resources) asks for clarification that the releasing shipper may specify a minimum price. The Commission so clarifies.

(5) Consistency Of Release Conditions With Pipeline Tariff

ANR asks the Commission to clarify that any conditions and/or restrictions that may apply to the released capacity must be consistent with ANR's tariff and/or the original agreement between ANR and the releasing shipper. The Commission clarifies that all terms and conditions must not conflict with the pipeline's tariff, but notes that, under section 284.243(f), the pipeline may agree to release the releasing shipper from liability under its contract. In addition, of course, the releasing shipper

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148. *See* Order No. 636 at p. 30,418.

can establish additional terms and conditions specific to its release, such as providing for recall rights.[149]

(6) Other Preferential Terms And Conditions

The American Paper Institute is concerned that potential releasing shippers may attempt to add terms and conditions which will tie the release of capacity to other compensation paid to the releasing shipper, such as an LDC requiring the potential replacement shipper to pay a certain price for local gas transportation service or a producer conditioning the release of capacity on the purchase of the producer's gas. The American Paper Institute requests the Commission to clarify that such ties will not be permitted. Brymore is concerned about the possibility of abuse by releasing shippers favoring affiliates or requiring compensation outside of the reassignment process.

The Commission shares these concerns. The Commission reiterates that *all* terms and conditions for capacity release must be posted and nondiscriminatory, and must relate solely to the details of acquiring transportation on the interstate pipelines. Release of pipeline capacity cannot be tied to any other conditions. Moreover, the Commission will not tolerate deals undertaken to avoid the notice requirements of the regulations.

d. Releasing Rights Of Holders Of Upstream And Downstream Capacity

The Commission in Order No. 636 provided for flexible delivery points, in part, to achieve a broad and meaningful capacity releasing program. [150] The Commission provided that

149. Order No. 636 at p. 30,418.

150. Order No. 636 at p. 30,429.

such delivery points must be within the firm transportation capacity to which the shipper is entitled and, as an example, pointed out that a downstream LDC could deliver capacity upstream, but that an upstream LDC could not deliver gas downstream.[151]

Arizona Electric Power Cooperative, Inc. (Arizona Electric) argues that the Commission should not prevent a downstream replacement shipper from using an upstream shipper's capacity and adding additional downstream capacity to complete the journey. Arizona Direct Customers interprets the Commission's discussion as a prohibition on releases by upstream customers and contends that such a rigid interpretation should not prohibit "operational" releases on grid-like transmission networks where, it asserts, substantial deliveries are by displacement. Alabama Gas asks the Commission to modify Order No. 636 to provide that downstream shippers may not reallocate their capacity to shippers seeking upstream receipt points. It argues that permitting downstream shippers to release capacity upstream is unfair because the upstream shippers do not have the reciprocal ability to release capacity in the downstream market. Alternatively, it argues that whenever a downstream shipper releases capacity to an upstream shipper, the "hole" remaining from the unused downstream capacity should be reallocated to an upstream shipper so that it can release capacity further downstream.

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151. As the Commission pointed out, a shipper with transportation capacity from the Gulf of Mexico to New York City could release any transportation capacity between those two points, including transportation for a shorter haul. Order No. 636 at pp. 30,420-21. Thus, the releasing shipper could release capacity from the Gulf of Mexico to Atlanta to one replacement shipper and, if feasible, simultaneously release capacity from Atlanta to New York to a second replacement shipper (or use that capacity to transport its own gas).

Appendix C

The Commission's discussion in Order No. 636 provided an illustration of the point that a shipper can release only that capacity it has a right to use and for which it is paying. Thus, the capacity release mechanism treats all shippers equally. The upstream shipper can release only the transportation capacity it holds by paying a reservation fee and cannot release capacity that it has not reserved.[152] Upstream shippers can, of course, purchase downstream capacity and combine it with other capacity for delivery to downstream points. Ultimately, the determination of the capacity available for release on each pipeline must be determined in the individual restructuring proceedings based on the operational characteristics of each pipeline, including such factors as the availability of flexible delivery points. The Commission will not permit the reallocation of capacity between upstream and downstream shippers as proposed by Alabama Gas. Such a proposal is not only unduly complex, but it would deprive the downstream shipper of the ability to sell capacity which it has reserved by paying the reservation fee.

e. Rate Cap

The Commission's regulations provide that the pipeline must allocate released capacity to the shipper offering the highest rate, not over the maximum rate. [153] Several petitioners raise questions about the maximum rate for released capacity set by this provision.

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152. For example, a shipper paying a reservation fee for capacity from point A to point B could release only that capacity, because it has not paid a reservation fee for capacity beyond point B.

153. Section 284.243(e).

Appendix C

(1) Elimination Or Modification Of The Rate Ceiling

Tenneco and Northwest Pipeline Corporation (Northwest) argue that released capacity should not be subject to any price cap. They argue that removing the price cap will permit capacity to be allocated to the user placing the highest value on the capacity and will eliminate the need for determining an allocation method when more than one party bids the maximum rate. Northwest contends that any amounts received above the maximum rate should be shared between the releasing shipper and the pipeline. Alternatively, Tenneco suggests that the rate cap should be based on an estimate of the costs of constructing additional facilities that otherwise would be necessary if capacity was not released.

Based upon the information in this proceeding, the Commission will not remove the rate cap because the market for released capacity has not been established to be sufficiently competitive so that releasing shippers will not be able to exert market power.[154] Thus, the extent of competition in the secondary release market may not be sufficient to ensure that the rates for released capacity will be just and reasonable. The Commission will not permit any replacement shipper to pay more than the Commission established maximum just and reasonable rate for capacity.

Permitting pipelines to share in amounts received above the maximum rate, as Northwest proposes, could permit the pipeline to recover scarcity rents through the release program that it

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154. *See* Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486, 1510 (D.C. Cir. 1984) (market forces must be sufficient to hold rates to reasonable levels).

would not ordinarily receive. Northwest's revenue sharing approach might further create an incentive for a capacity constrained pipeline to withhold new construction because of the prospect of deriving additional revenues from the resale of capacity above the maximum rate. The Commission further will not permit the maximum rate for released capacity to be based on construction estimates, because such a rate could exceed the maximum tariff rate on file for the pipeline.

Western Resources requests clarification of the maximum rate provision, contending that the benchmark for released capacity should be the interruptible rate and that some pipelines may not offer interruptible transportation after the restructuring. The Commission will clarify that the maximum rate for released capacity is the maximum firm rate, not the interruptible rate. Under the capacity release provisions of section 284.243, a customer is releasing firm capacity. The replacement shipper pays the pipeline both the usage rate and the reservation fee determined by the bidding process (up to the maximum rate). The releasing shipper then receives a credit for the reservation fee paid by the replacement shipper.[155]

(2) Items Included in Determining the Maximum Rate

Two petitioners raise questions about the items included in

155. The releasing shipper receives a credit toward its reservation fee because it pays this fee monthly to reserve capacity on the pipeline and the replacement shipper is acquiring the ability to use this reserved capacity. The releasing shipper does not receive a credit related to the usage fee because it has not paid the usage fee in advance. The usage charge reflects the pipeline's variable cost and is paid on the volume of gas actually shipped. After the release of capacity, the replacement shipper, not the releasing shipper, is the party shipping gas and therefore the replacement shipper is responsible for paying the usage charge to the pipeline.

the rate cap and about the treatment of refunds. AGD asks whether the rate cap includes all surcharges applicable to the capacity (e.g. transition costs and GRI charges) and the administrative fee and the revenue-sharing amount ("incentive fee"). Phillips Petroleum Company, Phillips Gas Marketing Company and GPM Gas Corporation (Phillips) argue that replacement shippers should share in refunds if the replacement shipper is paying more than the ultimately determined just and reasonable rate. The Commission agrees that the cap should include all fees paid by the releasing shipper, which would include surcharges and transition costs, and that replacement shippers can, in appropriate circumstances, share in refunds if their rate exceeds the just and reasonable rate ultimately determined.

But the Commission does not agree that the capacity can be resold at a rate including the pipeline marketing fee.[156] The marketing fee is not part of the cost of the transportation being released and the replacement shipper should not pay more than the maximum transportation rate for the capacity it is acquiring. The marketing fee represents the cost of finding a replacement shipper and therefore the releasing shipper should pay this fee, since it is the one marketing the capacity.

(3) Incremental Rates

Midland Cogeneration and Southern California Edison Company (SoCal Edison) raise issues regarding the application of the capacity release mechanism to pipelines with incremental or "vintaged" rate structures and Midland Cogeneration requests

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156. As discussed later, the Commission is no longer permitting pipelines to recover the costs of operating the capacity release mechanism through an administrative fee.

a technical conference on this issue. Midland Cogeneration contends that under vintage pricing rate schedules, incremental customers will effectively be shut out from participating in the capacity releasing because they are competing to release capacity with rolled-in customers paying a much lower rate. It asserts that the incremental customer therefore will not be able to mitigate its capacity costs while rolled-in customers will have excellent prospects of recovering all their capacity costs. Midland Cogeneration and SoCal Edison put forward a number of solutions to this problem, including revenue pooling, granting priority to incremental releases, and establishing a single price floor based on the incremental rate or an average rate.

The Commission cannot and will not make a generic determination on the various methodologies proposed by Midland Cogeneration and SoCal Edison since resolution of such issues may depend on the characteristics of the pipeline and the services it offers. The parties in restructuring proceedings involving incremental rates should consider and propose methodologies to ensure that the capacity release mechanism operates efficiently and that all parties are treated fairly and equitably, without undue discrimination.

f. Credits To Releasing Shippers

(1) Credits Exceeding Reservation Fee

In section 284.243 (f), the Commission provided that releasing shippers will receive a credit towards their reservation fee for the proceeds of any release. A number of petitioners have raised the issue of whether releasing shippers can retain revenues exceeding their reservation fee if they pay discounted rates. Western Resources asks the Commission to clarify that if the rate paid by the replacement shipper is greater than the rate

paid by the releasing shipper, the capacity holder should receive a credit for the release revenues and thereby receive the benefit of its bargain in gaining a long-term discounted rate. On the other hand, ANR argues that if the net revenues from the release exceed the releasing shipper's reservation fee, the pipeline should retain the incremental revenues, because that is consistent with the Commission's intent to allow the marketplace to set the price of services and would prevent overcontracting for firm capacity. Northern Natural Gas Company (Northern Natural) contends that the Commission should not permit discounted firm transportation to be released. It contends that the pipeline entered into those contracts based on the needs of the customer and the particular competitive situation with respect to end use markets and suppliers and that it would be inequitable for the discounted shipper to release that capacity. CIG asks that pipelines be allowed to address, in their restructuring proceedings, whether and to what extent capacity releasing shippers must share their revenue with other system users.

The Commission clarifies that a releasing shipper paying discounted rates is entitled to receive proceeds from a release even if such proceeds exceed its reservation fee. This ensures that shippers holding capacity have the incentive to release that capacity when others place a higher value on the capacity than the capacity holders do. The Commission will not limit competition by exempting discounted fixed-rate firm contracts from the capacity release mechanism nor will it permit the pipeline to retain incremental proceeds. Since the pipeline is not releasing the capacity, no efficiency or other procompetitive goal would be furthered by allowing it to retain incremental proceeds. If shippers holding discounted transportation are permitted to release that capacity, the pipeline is no worse off; the pipeline still receives the same total reservation charge for which it contracted with the releasing shipper.

(2) Credits For Capacity Not Sold

Brooklyn Union suggests that, even if released capacity of one month or more is not resold, the pipelines should credit the releasing shipper with an amount based on the pipeline's return on equity and related taxes. It argues that its proposal would provide pipelines with an incentive to maximize throughput by placing pipelines at risk for the same proportion of fixed costs as the MFV rate methodology and would therefore obviate the need to mitigate costs in connection with SFV rates. The Commission rejects this proposal. Under the releasing mechanism, the pipeline should not be at risk for selling capacity held by shippers; the releasing shippers have contracted for the capacity and therefore they should bear the risk if the capacity cannot be resold.

g. Effect Of Capacity Release On Interruptible Transportation

(1) Requirement To Provide Interruptible Transportation

American Paper Institute claims that one pipeline proposed to discontinue offering interruptible transportation based on Order No. 636 and requests the Commission to clarify that pipelines will still be required to provide interruptible transportation after implementation of Order No. 636. Section 284.9 of the Commission regulations specifically requires that interstate pipelines must "offer transportation service on an interruptible basis."

Appendix C

(2) Contribution Of Interruptible Transportation To Recovery Of Fixed Costs

A number of petitioners raise questions about the cost allocation and revenue responsibility to be assigned to interruptible transportation after capacity release has been implemented.[157] They point out that the Commission's traditional approach has required that interruptible transportation customers contribute to the recovery of the pipeline's fixed costs based on an estimated volume of interruptible transportation. However, they contend that once capacity release is implemented, interruptible transportation will face competition from released capacity and that estimating the volume of interruptible transportation that will be sold, and its rate, will be exceedingly difficult, particularly since the parties have no prior experience with a capacity release program. Some petitioners contend that if fixed costs remain in interruptible rates and interruptible volume or average interruptible rates decrease, the pipeline may not be able to recover the costs assigned to interruptible transportation.[158]

Some of these petitioners propose that the Commission depart from its previous practice of projecting interruptible volume and revenues and instead set firm rates without considering interruptible transportation.[159] If the pipeline is able to market interruptible transportation, the pipeline would then have to credit such revenues to the firm capacity holders. They

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157. *E.g.*, Northwest, Western Resources, Questar, NIEP, APGA, New Jersey Natural, Municipal Gas Authority of Georgia, and INGAA.

158. Questar and INGAA.

159. Northwest, Western Resources, NIEP, and APGA.

propose, to provide the pipeline with an incentive to market interruptible transportation, the pipeline would retain a portion of the proceeds as a marketing fee.[160]

In Order No. 636, the Commission did not address the manner in which fixed costs should be allocated to interruptible service. However, the Commission recognizes that the implementation of capacity release mechanisms and the potential use of seasonal contract entitlements, discussed below, may affect the level of interruptible transportation and that the throughput mix between firm and interruptible services, therefore, will have to be considered by the parties in the restructuring proceedings.[161] The parties to the restructuring proceedings may agree upon an appropriate allocation of throughput and cost to interruptible transportation. However, when the amount of interruptible transportation is uncertain, the parties should consider some type of a revenue crediting mechanism.[162]

As an example of this potential approach, the pipeline and its firm shippers might decide to attribute no revenue

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160. The American Paper Institute contends that the pipelines need incentives to continue to market interruptible transportation and proposes a revenue crediting approach. On the other hand, Michigan Gas Utilities Division of Utilicorp United Inc. (Michigan Gas) proposes a revenue sharing approach intended to mitigate the pipeline's incentive to prefer its own interruptible capacity over released capacity.

161. *See e.g.*, Columbia Gas Transmission Corp., 59 FERC ¶ 61,261 (1992); Stingray Pipeline Company, 59 FERC ¶ 61,372 (1992).

162. *See* Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295, at 62,057 n.49 (1989) (benefit sharing possible solution to difficulty of estimating amount of discounting).

responsibility to interruptible transportation.[163] Since the pipeline's firm shippers would be responsible for all pipeline costs, revenues from the sale of interruptible transportation would be credited to the firm shippers.[164] Under this potential approach, the parties to the restructuring proceedings also may consider whether other methods are needed so that the pipeline would not have an incentive to favor the sale of either interruptible or released capacity over the other service.

(3) Pipeline Preferences

Several petitioners are concerned about the pipelines giving preference to their own interruptible or repackaged capacity over released capacity and some have requested that the Commission either establish specific remedies for pipeline abuse or require the staffing and facilities for capacity release to be separate from the transportation and gas marketing personnel and facilities.[165] Michigan Gas and New Jersey Natural contend that the pipelines have an inherent advantage in selling interruptible capacity, because the releasing mechanism may not make time-sensitive releases possible and the pipelines may offer an interruptible rate lower than a posted release rate, thereby inducing potential replacement shippers to refrain from bidding for the posted

163. The pipeline's maximum interruptible rate would be derived from the firm rate, such as by converting the maximum firm rate into a daily rate.

164. A full credit of all interruptible revenues to firm shippers may not be appropriate if the pipeline has some revenue and cost responsibility (such as GSR costs) allocated to interruptible transportation.

165. NASUCA, Fuel Managers Association, Public Utilities Commission of the State of California (CPUC) (requesting specific remedies if pipelines seek to thwart the release process), and UGI (separation of personnel).

released capacity in the expectation that they could obtain interruptible transportation more cheaply.

The Commission in Order No. 636 has provided, in section 284.8 (b)(2) & (3), that pipelines cannot discriminate between released capacity and the pipeline's unsubscribed firm or interruptible capacity. The Commission sought to prevent attempts to circumvent or thwart the process by setting forth specific parameters to govern the capacity release mechanism. For example, the pipeline is *required* to post all capacity and contract with replacement shippers offering the best bid. In addition, the pipelines should design their restructuring proposals in a way that does not provide them with the financial incentive to favor the sale of their interruptible transportation (or their own repackaged capacity) over the sale of released firm capacity by other shippers.

As a further effort to eliminate requirements that might provide pipeline interruptible transportation with advantages over released firm capacity, the Commission is revising its position on the pipelines' collection of the administrative fee for operating the capacity release mechanism. As discussed below, the Commission is no longer permitting the pipelines to recover the costs of operating the capacity releasing mechanism through a separately stated administrative fee. The pipeline will recover these costs in its rates as part of its cost of service.

At this point, therefore, the Commission sees no necessity to provide for further control over the process, such as requiring further separation of functions or devising specific penalties for pipeline abuse. The Commission also does not believe any changes in the capacity release program are necessary to address the concerns of Michigan Gas about short-term releases or the ability of pipelines to undercut rates for released firm capacity.

First, as discussed previously, the Commission is modifying its regulations to ensure that short-term releases can take place by exempting releases of less than thirty (30) days from the bidding requirements of the rule. Second, as discussed above, the Commission will examine restructuring proposals to ensure that the pipelines do not have financial incentives to favor the sale of interruptible transportation over released capacity. Moreover, under the capacity release program, a releasing shipper can design its release with no minimum price term. Thus, the pipeline would not know the final bid rate in advance so that it could undercut that rate. Additionally, a potential replacement shipper that waits for the availability of interruptible transportation is taking a risk that another customer will acquire the released firm capacity, so that interruptible transportation is no longer available.

h. Administrative Issues

(1) Administrative Fee

In Order No. 636, the Commission stated that the pipelines could charge a reasonable administrative fee to cover their out of pocket expenses in connection with establishing and operating capacity releasing programs. It also provided that the pipelines could share in the proceeds of a release when the pipelines take affirmative action to market the released capacity and find the replacement shipper.[166] A number of petitioners request the Commission to clarify various items relating to the administrative fee. They assert that the pipeline should not be able to recover excessive revenues from the administrative fee,[167]

166. Order No. 636 at pp. 30,419-20.

167. United Distribution Companies, State of Michigan and Michigan (Cont'd)

the fee should be separately stated,[168] the pipeline should return the administrative fee when it allocates its own capacity,[169] and the pipeline should only be able to share in proceeds when it finds a replacement shipper.[170]

As discussed previously, the Commission will no longer permit the pipelines to recover their costs for operating the capacity release program through a separately stated administrative fee in order to eliminate any potential advantages that interruptible transportation may enjoy relative to released capacity. The pipeline should recover the fixed costs for establishing the bulletin board in its transportation rates as part of its cost of service.[171] The Commission will clarify that the pipeline may receive a marketing fee when the releasing shipper reaches an agreement with the pipeline to actively market its capacity.

(2) Relationship Between Releasing And Replacement Shippers

Section 284.243(f) provides that the releasing shipper

(Cont'd)
Public Service Commission (State of Michigan), and the Iowa, Missouri, and Wisconsin State Commissions.

168. INGAA.

169. State of Michigan.

170. United Distribution Companies.

171. The pipeline also could charge a fee to parties using the bulletin board that reflects the variable cost of such use (*e.g.* EBB staff, monthly
(Cont'd)

remains liable under its contract with the pipeline unless the pipeline releases it from its contract. The State of Michigan argues that since the replacement shipper must meet all of the pipeline's tariff provisions, the releasing shipper should not remain liable on the contract. Two petitioners request clarification of whether the releasing or replacement shipper ultimately is responsible for certain fees and charges, such as imbalance penalties and overrun charges.[172] Northern Illinois Gas argues that the capacity reallocation program "should automatically establish privity between the assignor and assignees so that the assignor can sue in the event it is billed by a pipeline for service provided to the assignee."

Due to the variety of possible releasing scenarios, the Commission believes that, unless the pipeline agrees otherwise, the releasing shipper must remain liable on its contract with the pipeline for payment of the reservation fee. The Commission will clarify, however, that the releasing shipper should not be responsible ultimately for penalties or other charges incurred by the replacement shipper. These charges are unrelated to the reservation of capacity and primarily are designed to deter shippers from engaging in certain prohibited conduct. No purpose would be served by requiring the releasing shipper to be responsible for these charges, since after the capacity release, it has no control over the conduct of the replacement shipper. The Commission will not establish contractual privity between the releasing and replacement shippers. The releasing shipper's

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telephone line charge, maintenance). This fee would ensure that those using the bulletin board more frequently, such as marketers, would be charged an amount relating to their use of the board and that their use would not be subsidized by infrequent users.

172. LILCO and ANR.

right to be subrogated to the pipeline's claim is a matter to be determined by law and the contract between the releasing shipper and the pipeline.

(3) Posting Of Offers To Purchase Capacity

Rochester Gas suggests that the Commission require pipelines to post on their electronic bulletin board offers to assume or purchase capacity. The Commission believes that this suggestion should be adopted in order to facilitate communication between buyers and sellers. Accordingly, the Commission will amend section 284.243(d) to require the pipelines to post offers to purchase capacity. In this situation, the shipper seeking capacity would have to pay any posting fee required.[173]

(4) Individually Certificated Transportation

In Order No. 636, the Commission stated that individually certificated non-part 284 transportation arrangements can be released under section 284.243 [174], but did not include this provision in section 284.243. Several petitioners[175] seek clarification that individually certificated transportation can be released or ask that section 284.243 be amended to conform to Order No 636's text. On reconsideration, the Commission has

173. Of course, if the offer to purchase resulted in an agreement to assign capacity, that agreement would be subject to the bidding requirements of the rule.

174. Order No. 636 at p. 30,418.

175. *E.g.*, Philadelphia Electric Company (Philadelphia Electric), LILCO, Northeast Energy Associates and New Jersey Energy Associates (Northeast Energy), New England Power Company (New England Power), SoCal Edison, and Questar.

determined that holders of individually certificated transportation under Part 157 should not be able to release capacity under the capacity release mechanism of Part 284, since they are not governed by Part 284 or affected by the provisions of Order No. 636 which revised the Part 284 regulations. Accordingly, the Commission will not amend section 284.243. Holders of individually certificated transportation may convert to Part 284 transportation if they wish to release capacity.

(5) Pregranted Abandonment

Under section 284.243 (b) and (f), a shipper can release its capacity permanently and, if the pipeline agrees to cancel its contract, the shipper will no longer be liable to the pipeline for reservation fees for that capacity. Texas Gas requests that, in this situation, the Commission clarify that the pipeline has pregranted abandonment authority to cease firm transportation to the releasing shipper. The Commission will clarify that pregranted abandonment applies. Section 284.221 (d) provides for pre-granted abandonment upon the "termination of each individual transportation arrangement . . . ."

4. Order No. 636 - Upstream Pipeline Capacity

New § 284.242 promulgated by the Commission in Order No. 636 provides that an open access upstream pipeline must permit a downstream pipeline to assign its firm transportation (including storage) capacity (whether Part 284 or individually certificated) on the upstream pipeline to the downstream pipeline's firm shippers, and that a downstream pipeline must assign its upstream firm transportation (including storage) capacity (whether Part 284 or individually certificated) to its firm transportation customers to the extent necessary to provide capacity to those shippers that desire upstream capacity.

Appendix C

a. Retention of Upstream Capacity by Pipelines

Tenneco, CNG, Southern Natural Gas Company (Southern), and Carnegie argue that pipelines should be permitted to retain upstream pipeline capacity to perform their merchant role, to avoid transition costs associated with buying out upstream supply contracts, or to perform their no-notice transportation. CNG points out that Order No. 636 permits pipelines to retain a share of storage upstream of the place of unbundling. CNG argues that it is likewise necessary for pipelines to retain a share of pipeline capacity upstream of the place unbundling to avoid a severe competitive disadvantage.[176] Southern also argues that the Commission "has not identified any evidence to support its determination that retention of upstream capacity has prevented other parties from gaining access to upstream supplies."

Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company (Columbia) argues that "[t]he Commission should permit pipelines to negotiate and file a different nondiscriminatory proposal for treatment of upstream capacity if it can demonstrate that the result is superior to mandatory assignment and that the Commission's goals are achieved."[177] In particular, Columbia argues that the Commission should "recognize that mandatory assignment of 'market delivery' contracts may not yield the best result on some pipeline systems."[178] Columbia asserts that those contracts are needed to

176. See also Texas Gas' argument that upstream pipeline capacity needed to serve existing pipeline purchase contracts for gas to be resold on an unbundled basis should be grandfathered. CNG and Texas Gas are referring to unbundled sales downstream of the product area.

177. Petition at 26.

178. *Id.*

avoid losing throughput.[179]

The Commission's intent is to afford gas purchasers the opportunity to purchase gas in the production area.[180] Capacity held by downstream pipelines on upstream pipelines is one limiting factor on the downstream pipeline's customers' ability to buy gas in the production area reached by the upstream pipeline. However, the Commission will permit upstream pipelines to retain production area capacity rights upstream of the place of unbundling, but only to the extent the pipelines need those rights in order to make their unbundled sales at their place of unbundling.[181] For example, if an upstream pipeline's unbundling point is at its mainline connection to a production area, it can retain capacity on laterals upstream of the unbundling point, if they are needed for the upstream pipeline to have an adequate opportunity to make unbundled sales at the unbundling point. The allocation of production area capacity upstream of the place of unbundling among the upstream pipeline and others seeking capacity must be done on a nondiscriminatory basis and the costs associated with the upstream capacity allocated to the pipeline must be recovered by the pipeline solely as part of its market-based sales rate.

The Commission will also permit downstream pipelines to

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179. Columbia describes "market delivery" contracts as "contracts under which gas is transported from gas supply areas to various locations throughout Columbia Transmission's system." *Id.*

180. Columbia's request for an exception for "internal capacity" contracts is discussed *infra*.

181. This is in addition to production area capacity needed for operational management and balancing and "no-notice" transportation.

retain some upstream pipeline capacity that is downstream of the place of unbundling on the upstream pipeline, but only to the extent such capacity is demonstrated by the downstream pipeline to be necessary for operational management and balancing purposes and the performance of the no-notice transportation service. For example, a downstream pipeline not connected to a production area but connected to an upstream pipeline (*e.g.*, Alabama-Tennessee Natural Gas Company (Alabama-Tennessee) and Tennessee Gas Pipeline Company) can retain capacity on the upstream pipeline to ensure that it has access to gas to keep its line pack in balance. However, the Commission will not permit a downstream pipeline to retain transportation or storage capacity on upstream pipelines to perform a sales service at the interconnection with an upstream pipeline. This is necessary to ensure that pipeline sales occur as far upstream on the pipeline grid as possible.

Nothing in this rule is intended to prohibit a transportation customer from contracting with a pipeline to act as its agent in nominating, scheduling, or otherwise managing its activities on the upstream pipeline, provided that the customer retains title to the capacity.

b. Upstream Supply Contracts

As stated above, the Commission is concerned about pipeline obligations under upstream supply contracts and has included costs incurred in connection with those contracts as transition costs to be recovered by the pipelines.[182]

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182. Texas Gas' argument that it should be relieved of its purchase obligation under stranded gas purchase contracts stemming from the assignment of upstream pipeline capacity is discussed, *infra*.

Tenneco argues that to reduce transition costs, "the Commission should require customers taking assignment of the upstream pipeline capacity, to take along with it an assignment of an equivalent amount of supply from the downstream pipeline's current suppliers."[183]

Northern Illinois Gas argues that "pipelines should be allowed to give priority to customers who will take the gas supplies associated with Account No. 858 capacity or who will purchase the inventory associated with the upstream storage."[184] Northern Illinois Gas would limit this conditioning of assignment to the restructuring proceeding but supports it then to reduce *transition* costs.

Similarly, Atlanta Gas argues that upstream pipeline capacity dedicated to a particular customer's certificated service should be allocated to that customer.

The Commission will not require downstream pipeline customers to take upstream supply along with upstream capacity. While that could limit transition costs, it would unfairly limit gas purchasers in their choice of gas merchants and, therefore, would be unduly anticompetitive. But the Commission encourages parties to voluntarily arrange assignments to minimize transition costs. Hence, Atlanta Gas' more general request is denied.

c. Length of Upstream Pipeline Assignments

Order No. 636 provided that upstream capacity assignments

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183. Petition at 13.

184. Petition at 29.

under section 284.242 are permanent. CIG asks that the Commission make it clear that the shipper acquiring that capacity does not obtain any extension rights (such as under an evergreen clause) except for the right of first refusal when the original agreement terminates.

The Commission disagrees with CIG. The Commission sees no reason why the downstream pipeline's evergreen rights should not be assigned to downstream customers under section 284.242. The downstream customer should stand in the shoes of the downstream pipeline, if the assignment occurs.

d. Abandonment

Texas Gas asks the Commission to provide for pregranted abandonment of the upstream pipeline's service obligation to the downstream pipeline with respect to the capacity assigned to downstream customers under section 284.242. The Commission clarifies such abandonment applies. The assignment is permanent and therefore terminates the contractual arrangement between the upstream and downstream pipeline. Section 284. 221(d) provides for pregranted abandonment upon the "termination of each individual transportation arrangement. . . ."

e. Relationship of Section 284.242 to Restructuring

Order No. 636 prevents the downstream pipeline from giving up upstream capacity in the restructuring proceeding except under 18 CFR 284.242. Northern Illinois Gas requests that the Commission permit those releases with the written consent of the participants in the downstream pipeline's

restructuring proceeding of an upstream pipeline.[185]

The Commission's concern was that customers of downstream pipelines have priority access to upstream transportation and storage capacity during the restructuring proceedings.[186] The Commission, therefore, will permit downstream pipelines to relinquish upstream capacity during the restructuring proceedings (see *infra* on restructuring relinquishment), if all of its downstream pipeline's customers consent to the relinquishment and there is someone willing to take the upstream capacity.[187] For example, with that consent, a downstream pipeline could give up upstream capacity under the mechanism established for capacity adjustments in the restructuring proceeding under 18 CFR 284.14 (e).

f. Use of Upstream Capacity

CIG asks for clarification that the assigned or released upstream capacity be subject to the receipt and delivery points specified in the existing contracts to prevent sales customers of downstream pipelines from fundamentally changing the use of the capacity. Similarly, Columbia maintains that the Commission

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185. See also National Fuel Gas Supply Corporation (National Fuel) — pursuit of upstream capacity reduction after notice and receipt of no objections.

186. However, this priority does not extend to customers of customers of downstream pipelines.

187. Brymore requests clarification that the upstream pipeline assignment policy of section 284.242 is to be a public process during the restructuring proceedings which upstream capacity is assigned in a nondiscriminatory basis and is not a "trading chip." The Commission so clarifies.

failed to consider the relationship among permanent assignment of upstream capacity, flexible delivery points, and its ability to deliver market requirements through the changed delivery point.

As stated above, the downstream pipeline is entitled to retain some upstream capacity below the upstream pipeline's point of unbundling, only if it demonstrates that it is needed for operational management and balancing and no-notice transportation purposes. In that light, the Commission sees no reason why assignees of capacity cannot change receipt and delivery points under the Commission's flexible receipt and delivery point policy, including changing primary points if firm capacity is available. Of course, the assignee must comply with the operational terms and conditions of the pipeline's tariff.

g. Exemptions

In Order No. 636, the Commission exempted certain arrangements from section 284.242's requirements with respect to the assignment of upstream capacity, specifically, to interruptible capacity held by downstream pipelines on upstream pipelines, firm capacity held by downstream pipelines on intrastate pipelines, and upstream exchange transactions.[188]

Baltimore Gas and Electric Company (BG&E) argues that the exemption is too broad and asks the Commission to clarify that "the exemption of firm capacity held by downstream pipelines on intrastate pipelines and upstream exchange transactions was not intended to apply to any such capacity that had been used in the past to support any service."[189]

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188. Order No. 636 at p. 30,418.

189. Petition at 7.

Appendix C

Mobil argues that while there may be exchanges necessary to pipeline operations or no-notice service, this issue should be resolved in the restructuring proceedings where the pipeline should justify the retention of exchanges.

Columbia maintains that the Commission should except "internal capacity" contracts where it delivers gas to the upstream pipeline and the upstream pipeline redelivers the gas back to Columbia at another point in its system. Columbia argues that these "internal capacity" contracts are analogous to exchanges and are needed to meet its delivery obligations without building new pipelines.

The Commission has no authority, in general, to order intrastate pipelines to permit the relinquishment of capacity used for intrastate services by their shippers to downstream customers. Accordingly, the Commission did not intend to subject Subpart C (intrastate) pipelines to section 284.242. The Commission encourages intrastate pipelines to participate in the restructuring proceedings and to voluntarily consent to any reassignment proposal in a restructuring proceeding on terms and conditions acceptable to it. This may be especially appropriate if the intrastate capacity, as suggested by BG&E, is needed to support service to a particular customer of the interstate pipeline. If a person believes that this is necessary in a specific case with respect to Subpart C capacity, it may petition the Commission to take appropriate action.

The Commission will continue to except exchanges and analogous transactions. Whether Columbia's "internal capacity" contracts qualify for such treatment is an issue for the restructuring proceeding. Those arrangements are too diverse and complex to be subject to a rule designed for upstream

pipeline capacity. However, as stated above, the downstream pipeline needs those arrangements only for operational management and balancing and no-notice transportation purposes. In addition, the Commission will not tolerate retention of exchanges and similar arrangements to force downstream sales customers to remain pipeline sales customers.

h. Application to Individually Certificated Service

Section 284.242 requires open access pipelines to permit the assignment of upstream pipeline capacity to customers of downstream pipelines. Questar observes that the text of Order No. 636 provides that individually certificated firm transportation (including storage) is subject to section 284.242, but that section 284.242 does not so provide. The Commission is amending section 284.242 to conform to the text of Order No. 636.

5. Buy/Sell Arrangements

As stated above, the Commission prohibited buy/sell arrangements once the pipeline's capacity releasing program is effective, but grandfathered such arrangements existing on that date provided they are posted on the electronic bulletin board for informational purposes. Most buy-sell issues will be considered in the rehearing order in *El Paso Natural Gas Co.*, which dealt with certain existing buy-sell arrangements.[190] Here, the Commission will discuss only those issues raised with respect to continuation of existing buy-sell arrangements and posting on the electronic bulletin board.

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190. 59 FERC ¶ 61,031 (1992). *E.g.*, the Commission's jurisdiction over buy-sell arrangements will be addressed in the order on rehearing, which is being issued contemporaneously with this order.

Appendix C

Cascade Natural Gas Corporation, the Washington Water Power Company (Cascade), and NIEP ask the Commission to confirm in the regulations that buy-sell arrangements survive as stated in the text of Order No. 636 and that surviving buy-sell arrangements continue through any evergreen or rollover period in the buy-sell contract or at least until existing financing arrangements for underlying IPP projects expire.

SoCal Edison states that it is concerned that an existing capacity holder may release capacity involving a buy-sell agreement and that the buy-sell party "may be temporarily without authorization to continue its transportation service pending the ability to retain the capacity (in its own name) as part of the pipeline's capacity releasing program".[191] It asks the Commission to clarify that the party using the grandfathered capacity will be allowed to continue to use it through and until that party decides whether to retain the capacity (in its own name) under the pipeline's capacity releasing program.

NIEP states that some buy-sell arrangements involve the pooling of capacity rights on several pipelines. They ask the Commission to clarify that "buy-sell pooling arrangements are valid and should be grandfathered under the Final Rule" and suggest that "an LDC, participating in an existing buy/sell program or a pre-arranged deal, may simply pro rate the amount of buy/sell or pre-arranged capacity pooled among all of the relevant pipelines, so that every pipeline may post such a pro rated amount on its bulletin board for informational or capacity reservation purposes, subject to change from time to time [or] . . . the LDC could notify its pipeline transporters of the pooling arrangements without attributing any specific buy/sell or pre-arranged volumes to any particular pipeline and simply indicate

191. Petition at 11.

that part of the LDC's reserved capacity will be used for that purpose."[192] They also ask the Commission to revise the rule to permit the buy/sell customers to pay the weighted average rates of the pipelines.

The Indicated Shippers argue that buy/sell arrangements should be terminated as of the date of the *El Paso* order or the date a capacity release program is instituted or should be subject to the "better offer" rule.

Generally, the Commission denies rehearing on these issues. The Commission will permit all grandfathered buy/sell arrangements to continue pursuant to their terms, including evergreen provisions in the contract in effect on the date of posting on the electronic bulletin board. This will permit the parties to those arrangements to receive the benefits of their bargain. The Commission observes that revised section 284.243(d) requires the pipeline to post offers to purchase capacity. Thus, customers receiving service under a grandfathered buy/sell transaction can use this provision to locate other capacity holders willing to offer a better deal.

The Commission clarifies that existing buy/sell pooling transactions such as that described by NIEP may be grandfathered. This should be done by posting the complete details of the pooling arrangement on the EBB of each pipeline involved in the pooling of capacity.

Marathon Oil Company (Marathon) argues that the grandfathering of buy/sell arrangements creates an erroneous disparity *vis a vis* sales to pipelines. It argues buy/sell deals should be phased-out. As of the effective date of the pipelines'

192. Petition at 6.

compliance with Order No. 636, no new buy/sell arrangements can be consummated. The Commission believes this balances all interests involved and provides a suitable transition to the Order No. 636 release program.

The Commission views the problem raised by SoCal Edison as a misunderstanding of releasing. While the LDC releases the capacity for resale, it does not lose its right to use that capacity until the replacement shipper has the right to use that capacity.

The Commission rejects Indicated Shippers' requests that grandfathered buy/sell arrangements be terminated. The Commission believes that the parties to existing buy/sell arrangements should receive the benefit of their bargains and should not be subject to losing those benefits under capacity releasing procedures.

D. No-Notice Transportation Service

New § 284.8(a)(4) adopted by Order No. 636 requires pipelines to provide a no-notice transportation service if they provided a bundled, city-gate, firm sales service on May 18, 1992. The preamble explained that this was required only if the sales service was provided on a no-notice basis.[193] Section 284.8(a)(4) describes no-notice service as "a firm transportation service under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty."

1. Nature and Definition of no-noticeTransportation

Petitioners raise a variety of questions about the nature and definition of no-notice transportation.

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193. Order No. 636 at p. 30,421.

Appendix C

The APGA raises the fundamental question about whether no-notice transportation obligates pipelines to deliver gas or simply to provide capacity. The APGA questions how a transportation service can be as adequate and reliable as a bundled sales service. Similarly, Citizens Gas & Coke Utility (Citizens Gas) argues that no-notice transportation service is not comparable to the currently available no-notice sales service because the Commission has not adopted provisions providing for the necessary gas supply. City Gas asks the Commission to clarify that no-notice transportation service will be available at the same quality level as the no-notice bundled sales service.

For other reasons, the pipeline industry also is concerned about the gas supply issue. INGAA and several pipelines[194] ask the Commission to clarify that the pipeline is not the guarantor of gas supply as was the case under the bundled, city-gate, firm sales service. For example, ANR argues that no-notice shippers must take responsibility that their supplies are adequate with the pipeline covering genuine market swings from nominations but not covering any shortages or imbalances, regardless of the cause or magnitude. PGT and Alabama-Tennessee argue that they cannot perform no-notice service or be the guarantor of adequate gas supplies because they have no storage. ANR states that to provide that back-up, the pipeline would have to "maintain an expensive inventory of redundant gas supply and/or capacity to ensure that deliveries are made to all shippers under all circumstances."[195] Tenneco maintains that the borrowing of gas will not solve any delivery problems at peak if the customers' gas has not been tendered to the pipeline.

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194. *E.g.*, Southern, Questar, CNG, Carnegie, Northwest, and ANR.

195. Petition at 8.

Appendix C

The Commission clarifies that the pipeline is required only to provide the capacity and operational flexibility necessary to ensure no-notice delivery of gas supplies owned by the pipeline's customers. It is up to the pipeline's customers to provide the gas for this service. The pipeline is not required to provide a back-up sales service to cover shortages or imbalances other than normal balancing associated with system integrity and efficiency. However, as part of that balancing service, a pipeline offering a no-notice transportation service must establish procedures to accomodate short-term reasonable differences between customer nominations for takes from the pipeline and actual takes of gas from the pipeline.[196] It is up to the pipeline's customersto make sure that sufficient gas is tendered to the pipeline to correct such imbalances in a timely fashion. The pipeline is required only to provide physical resources and operational procedures needed to accommodate such imbalances. Because pipeline systems differ, the parties to the restructuring proceedings must define the meaning of short-term reasonable differences and the time in which imbalances must be corrected.

The Commission does not agree that a lack of storage excuses a pipeline from its no-notice obligations. If a pipeline has been able to provide bundled sales service with a no-notice characteristic, the Commission will require that the pipeline use the same physical and operational assets to provide a no-notice

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196. The procedures used to accommodate short-term differences between nominations and actual deliveries to the customer can involve several individual services that together provide the no-notice transportation service. For example, the pipeline may offer to provide no-notice transportation where it balances the customer's imbalance out of the customer's gas in contract storage or the pipeline's own storage gas, with the customer making up the use of the pipeline's storage gas in a reasonable period of time.

transportation service. Even where a pipeline has no storage, it can maintain operational control over gas receipts by issuing operational flow orders or by acting as the scheduling agent for its shippers (if they so choose), if necessary to provide no-notice transportation. Such operational control will, for example, enable the pipeline to build line pack in advance to support peak delivery requirements.

The Commission, however, is also encouraging pipeline shippers to cooperate with the pipeline in developing arrangements to efficiently implement no-notice service. For example, this could be accomplished by having contractual arrangements that allow the borrowing of gas by one customer from another customer.

NGSA argues that the definition of no-notice transportation is unclear. NGSA is concerned that the current definition could be viewed as requiring a single, restrictive no-notice service rather than permitting the flexibility needed to ensure optional services. NGSA asks the Commission to clarify that "no-notice transportation service simply entails an optional enhancement of basic firm transportation services which gives the firm transportation customers greater flexibility to meet unscheduled requirements within certain tolerances."[197] NGSA describes "tolerances" as degrees of flexibility above and below the customer's nomination within which it will not be penalized; that is, "an excused nomination inaccuracy." NGSA maintains that the degree of nomination inaccuracy permitted is a matter for negotiation between the pipeline-transporter and its shipper customers. United Distribution Companies asks the Commission to revise the rule to prohibit pipelines from restricting 'no-notice' service to limited or 'peak day' periods. The Industrial Groups argue that clarification is needed about whether the customer

197. Petition at 18.

may demand 100% of its post Order No. 636 firm transportation service, rather than some lesser percentage, to be provided under a no-notice FT rate schedule. ANR argues that pipelines should be entitled to impose daily penalties on a nondiscriminatory basis because flow control installations would be very expensive.

As a general matter, the Commission observes that some of the arguments made concerning alleged problems with no-notice transportation service appear to be thinly veiled arguments by those who favor continued pipeline bundled sales service. The Commission makes it clear that: 1) no-notice transportation service must be offered, as required below, as a pipeline service; 2) no legitimate operational reason has been given why no-notice transportation service cannot be as reliable as no-notice bundled sales service; and 3) the Commission will not tolerate *any* attempt to frustrate the orderly operation of no-notice transportation service. Thus, the pipelines are required to offer 100 percent no-notice service on all days of the year. However, the pipelines are encouraged to offer additional variations of no-notice service, if that suits the needs of their customers as suggested in Order No. 636.[198]

As stated above, several petitioners (e.g., the APGA) refer to the no-notice transportation service as hypothetical or untested or untried. However, the Commission, as stated above, believes it is fully warranted in its prediction that the pipelines can provide a reliable no-notice transportation service.[199] In Order No. 636, the Commission briefly described in general how the

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198. "The pipeline could also offer different daily imbalance management options based on a customer's desired tolerance above expected scheduled quantities and allowed tolerances." Order No. 636 at p. 30,425.

199. *See* Mississippi River Transmission Corp. v. FERC, *supra*, ("No

(Cont'd)

pipelines could provide that service to their former sales customers.[200] In the next sections, the Commission will further explain how it envisions no-notice transportation service could be provided.

a. Example: Production area-to-market pipeline with storage

Under a no-notice transportation service, a shipper could nominate and schedule its anticipated daily requirement from suppliers attached to the pipeline. During the gas day the shipper could be permitted the flexibility to take delivery of gas greater or less than its scheduled volume, within its maximum daily quantity (MDQ), resulting in a daily imbalance on the pipeline. The pipeline could handle the imbalance by adjusting injections or withdrawals from storage, or to a lesser extent, by increasing or decreasing line pack.

Pipelines could utilize unused contract storage capacity and deliverability to cover a shipper's daily imbalances. Gas withdrawn from storage could be borrowed from or displaced with customer storage accounts and replaced within days when the no-notice shipper corrected its imbalance. To assure that contract storage is available when called upon by the contract storage customer, the pipeline could limit no-notice overtakes when storage customer withdrawal nominations approached maximum storage deliverability or when working gas was below certain levels. If contract storage usage patterns routinely leave

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(Cont'd)

legitimate explanation being apparent, we see no reason to question FERC's implicit conclusion that bundled and unbundled service are adequate substitutes for each other." slip op. at 10).

200. Order No. 636 at p. 30,425.

contract storage capacity or deliverability unavailable for imbalance management, the pipeline could use retained storage to support the no-notice service. If operating conditions require limitations of no-notice service, these limitations should not be any more restrictive than those that existed for bundled sales service as of May 18, 1992.

b. Example: Downstream pipeline

This example applies to no-notice transportation service on a downstream pipeline that currently purchases gas from one or more upstream pipelines. Under the final rule, capacity on upstream pipelines must be assigned to the downstream pipeline's customers wanting that capacity, but, the downstream pipeline can also retain some upstream capacity to support the no-notice service, but only when it has demonstrated the need to hold this capacity to fulfill its no-notice service obligation. If the downstream pipeline does not retain upstream capacity for this purpose, one possible way in which it could provide the no-notice service is for the customers of the downstream pipeline to grant it agency rights to schedule no-notice services on upstream pipelines.

A no-notice shipper on a downstream pipeline could nominate its daily requirement, specifying volumes to be received from individual upstream pipelines. However, the downstream pipeline could perform the actual nomination and scheduling of the shipper's no-notice service on the upstream pipeline. Thus, when a customer on the downstream system invoked its no-notice right to take more gas, for example, than scheduled on that day, the downstream pipeline could in turn take more no-notice gas from the upstream pipeline than scheduled. When multiple upstream pipelines are involved, the downstream pipeline could follow a prespecified order in

selecting the upstream no-notice service, as specified by the downstream shipper. The downstream pipeline could override the preferred priority order, to use different receipt points for example, as necessary to maintain system integrity. Thus, the no-notice imbalance could be handled by adjusting takes from the upstream pipeline as needed to keep the downstream system in balance. Reliance on upstream no-notice services, with operating control in the hands of the downstream pipeline, provides downstream systems the ability to provide no-notice services even if they possess no storage of their own.[201]

2. Availability of No-Notice Service

INGAA, United Gas Pipe Line Company (United), ANR, and CIG ask the Commission to limit no-notice transportation service to existing sales customers at current delivery points with the option to provide the service beyond that on a nondiscriminatory basis if the pipeline has the facilities and delivery capacity.

Northwest asks the Commission to clarify whether pipelines must offer a no-notice transportation service option to customers that have already left the pipelines' traditional sales service for pre-Order No. 636 transportation. Northwest states that no-notice service without balancing and scheduling penalties does not now exist on its system and seeks clarification that it does not have to rebundle to a quality level which exceeds traditional bundled sales.

Questar argues that a shipper should be entitled to no-notice transportation service only if it asks for it during the restructuring proceeding.

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201. The imputed load factor for the small customers' firm transportation rate applies to "no-notice" transportation as well.

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NASUCA asks the Commission to clarify that "all pipelines should be required to offer a no-notice transportation service in the future regardless of whether they were providing a bundled, city-gate, firm sales service on the effective date of the rule."[202] Similarly, Southwest Gas Corporation (Southwest Gas) states that the Commission must ensure that pipelines already unbundled, such as El Paso Natural Gas Company (El Paso), must be required to perform a no-notice transportation service to avoid any undue discrimination.

The pipelines are required to offer no-notice transportation service only to customers that were entitled to receive a no-notice firm, city-gate, sales service on May 18, 1992. The pipeline must provide no-notice service at flexible delivery points for those customers. Pipelines that did not provide a no-notice sales service on May 18, 1992, are not required, but are strongly encouraged, to offer a no-notice transportation service. The pipeline's sales customers must inform the pipeline in the restructuring proceedings what form of transportation service they want to receive starting on the effective date of the pipeline's compliance filing. This is a one-time right to elect no-notice transportation. The pipelines are not required to offer no-notice service to other customers because they have not been receiving such a service.

A pipeline may, of course, offer no-notice service to transportation customers other than those who qualify for such service. If a pipeline offers to provide this service to a broader group of customers than required, the pipeline is required to do so on a non-discriminatory basis and, to the extent capacity is available, customers may then elect no-notice service at any time. The Commission strongly encourages the pipelines to make

202. Petition at 33.

no-notice transportation service available to the maximum extent possible.

3. Direct Sales

The Industrial Gas Users Conference asks the Commission to indicate how, if at all, Order No. 636 affects nonjurisdictional direct sales arrangements. It states that the Commission probably intended to unbundle direct sales service. If so, it argues that those customers should have access to the full range of transportation rights and services, including no-notice firm service, traditional open access firm transportation, and storage.

Direct sales must be unbundled under Order No. 636.[203] Direct sales customers are entitled to receive the same type of transportation service that was embedded within their bundled direct sales service.[204] Hence, they are entitled to receive no-notice transportation service only if their direct sales were provided on a no-notice basis. Similarly, they are entitled to an allocation of firm storage only if firm transportation was embedded within their direct sales service.

4. The Meaning of Firm Entitlement

Section 284.8(a)(4) of the regulations promulgated by Order No. 636 provides that:

> An interstate pipeline that provided a firm sales service on May 18, 1992, and that offers

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203. 18 CFR 284.284(b) and (c) convert bundled sales under any service agreement to unbundled service.

204. See *infra* on storage.

> transportation service on a firm basis under subpart B or G of this part, must offer firm transportation service under which firm shippers may receive delivery up to their *firm entitlements* on a daily basis without penalty.[205]

The Industrial Groups question what "firm entitlements" refers to and ask whether they are 'firm entitlements' under (1) its existing firm sales contracts, (2) its existing firm sales and transportation contracts combined, or (3) the new firm transportation entitlements in the service agreements to be entered into under the new no-notice FT rate schedules.

The Commission clarifies that "firm entitlements" refers to the firm shippers' daily right to receive transportation service. As stated *supra*, the firm shipper has a right to receive a no-notice transportation service only if it received a no-notice sales service on May 18, 1992. Under section 284.284(b) of the regulations adopted by Order No. 636, the sales customer's firm rights are converted to an equivalent amount of firm transportation service. Hence, firm entitlements means the converted firm entitlements to which a shipper is entitled to receive no-notice transportation service under Order No. 636.

5. The Meaning of Equivalent Amount of Transportation Service

Under new section 284.284(b), a pipeline customer's firm sales entitlements are converted to an equivalent amount of unbundled firm sales service and an equivalent amount of unbundled firm transportation service, except as adjusted in the

205. 18 CFR 284.8(a)(4) (Emphasis added.)

restructuring proceedings. Texas Gas sees an ambiguity between section 284.284(b) and the preamble to Order No. 636, which states that pipelines may offer a bundled transportation service consisting of transportation and storage to perform no-notice service. Texas Gas asks for clarification that former bundled sales customers are to receive the same quality and quantity of transportation service they were previously receiving before unbundling.

The Commission clarifies that former bundled sales customers are entitled to receive the same quality and quantity of transportation service they were previously receiving as part of their sales service before unbundling. The Commission's reference to a bundled transportation and storage service was meant to highlight one of several possible ways to achieve that result through use of no-notice transportation service. The Commission notes that the central point is that the no-notice transportation must be at least as reliable as the service the bundled sales customers were actually receiving. On many systems, the pipelines could not deliver their full daily contract demand obligation on every day of the year because that was operationally impossible. The Commission is not requiring the no-notice transportation service to be superior to the bundled sales service in that respect.

6. Timing of Implementation

The Wisconsin Distributor Group states that it is concerned about the difficulties in implementing no-notice service and suggests a transition period where a pipeline would offer both bundled sales and no-notice transportation with an annual conversion process.

Elizabethtown Gas Company (Elizabethtown) argues that

the Commission erred by not ordering the implementation on an interim basis, as it did in the case of Transcontinental Gas Pipe Line Corporation (Transco), with a conference on each pipeline after one year's operation.

The requests have not indicated a need for generic interim or transition periods with respect to implementation.

7. Flow Control

CIG asks the Commission to clarify that "imposition of operational conditions requiring that no-notice shippers maintain storage inventory levels and flowing gas supplies in the same relative mix as the pipeline currently relies upon to operate its sales service is consistent with the concept of no-notice delivery service."[206]

ANR asks the Commission to clarify that pipelines "cannot be held liable to producers, shippers, or consumers, as a result of any actions taken pursuant to [operational flow] orders."[207] ANR seeks clarification that for operational reasons it can order shippers located in an area to buy gas, whether their specific market area requires it or not. Last, ANR argues that pipelines should be able to impose daily penalties on a nondiscriminatory basis because flow control installations are very expensive.

Cincinnati Gas argues that allowing parties to craft operational control provisions in the restructuring proceedings is fundamentally inconsistent with pipelines retaining operational control to the degree they have it today.

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206. Petition at 15.

207. Petition at 9.

Appendix C

United Distribution Companies asks the Commission to revise the rules to prohibit pipelines from unilaterally imposing "flow control" or other control devices restricting LDC ability to take gas at city-gate stations.

The Commission clarifies that pipelines have the right to impose reasonable operational conditions and to issue, on a nondiscriminatory basis, operational flow orders without liability, except for negligence or undue discrimination, to be able to provide a no-notice transportation service. The Commission sees no inconsistency between permitting parties to participate in crafting the operational control provisions needed for no-notice service and the pipelines retaining operational control. Of course, the pipeline must include in its tariff all operational terms and conditions related to no-notice transportation service so that the Commission can review the reasonableness of those terms and conditions, and so that shippers will have notice as to what will be asked of them.

The Commission views the control of flow from the pipeline to the city-gate as an important issue to be resolved in the restructuring proceedings. The parties should consider flow control devices as well as other methods, such as the use of overrun penalties. The Commission will not permit penalties for service within daily firm entitlements covered by no-notice service. If a pipeline elects to impose flow control or other control devices, the Commission will consider any opposition to that election in the compliance filing order.

8. Control of Facilities

United asks the Commission to "confirm that each pipeline's own characteristics must be taken into account in the settlement proceedings which will restructure individual proceedings" and

to make an explicit statement of the pipeline's need to have adequate control over its operations "because of the bidirectional flow necessary to maintain peak capacity." The Commission so confirms, as long as it is accomplished on a non-discriminatory basis.

9. Supply Reallocation/Borrowing

In Order No. 636, the Commission suggested the possibility that parties could agree to the borrowing of one customer's gas to ensure no-notice transportation service for another shipper.

NGSA requests clarification with respect to the "borrowing" of a shipper's gas to keep the system in balance and to provide no-notice service. It urges that the LDC may only take gas belonging to the LDC and that once an interruptible shipper's gas is in the system it may not be diverted unless pursuant to a contractual arrangement between the LDC and the interruptible shipper. Phillips similarly argues that pipelines should be able to take producers' supplies for operational and no-notice purposes only pursuant to contract and suitable compensation.

United asks the Commission to explicitly recognize that the pipelines will have no liability for supply curtailment or reallocation among customers conducted under the terms of their individual tariffs.

The State of Louisiana seeks clarification that "a pipeline may [not] 'borrow' gas from some customers to serve others at a time when the customer from which the gas is 'borrowed' itself has need for the gas."[208]

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208. Petition at 6.

The Commission views the pipeline's rights and obligations in connection with the borrowing of gas as matters to be addressed and resolved in the individual restructuring proceedings. As the above example of no-notice transportation in this Part illustrates, it is necessary to balance the pipeline's need to borrow gas with its obligation to return borrowed gas on demand. These matters are pipeline-specific depending on particular pipeline needs and must be included in the pipeline's tariffs so that the Commission can determine if they are reasonable and so shippers will have notice of what might happen. As a general matter, the Commission believes that a borrowing of gas should be pursuant to contract and appropriate compensation.

10. Effects of No-Notice Transportation on Other Services

SoCal Edison asks the Commission to clarify Order No. 636 by adopting a "quality of service" principle to ensure that existing transportation customers are treated in a non-discriminatory fashion when pipelines implement their tariff provisions and operating conditions for no-notice transportation. It argues that this is especially important to ensure that existing transportation customer gas is not curtailed before, or in a discriminatory manner with respect to, no-notice gas.

The Fuel Managers Association seeks clarification that no-notice transportation "may not degrade the 'traditional' firm transportation service."[209] It asks that the Commission clarify that a pipeline may not divert traditional firm transportation gas supplies or interrupt that service to meet the needs of no-notice customers. Similarly, the Industrial Groups are concerned that

209. Petition at 9. See also Destec.

pipelines may undermine traditional firm service by 'prioritizing firm customers' call on line pack to provide 'no-notice' service.

Brooklyn Union, *et al.*,[210] PSE&G, and AGD ask the Commission to clarify that the operating restrictions of no-notice transportation will not impair other existing firm services or create more onerous conditions on existing firm transportation and contract storage services.

As a general matter, the Commission agrees that existing transportation and storage services should not be diminished in quality. However, as with the borrowing of gas discussed above, the parties to the restructuring proceedings should resolve questions concerning the relationship of no-notice transportation to other pipeline services in each proceeding. Of course, the pipeline must include all of its operational terms and conditions in its tariff so that the Commission can determine if they are reasonable and so that all shippers will know the terms and conditions of the no-notice service.[211]

11. Unbundling Options

The APGA asks the Commission to clarify that a sales customer, upon unbundling, can elect either no-notice or traditional transportation service. The Commission clarifies that upon unbundling a sales customer, at its election during the

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210. ConEd and PSE&G.

211. The Commission, as requested by Brooklyn Union, *et al.*, confirms that holders of firm storage capacity have priority to use of that capacity, subject however, to the pipeline's tariff provisions with respect to storage use and the availability of interruptible storage when operationally warranted. Order No. 636 at p. 30,427.

restructuring proceeding, may choose no-notice or traditional firm transportation or a combination of the two. However, as stated above, the customer may elect no-notice transportation only at that time unless the pipeline offers no-notice transportation in the future as a service to all customers.

12. Other Forms of Transportation Service

Tejas, in its supplemental motion for clarification, asks the Commission to clarify that pipelines may offer transportation service in addition to no-notice and traditional firm transportation. Tejas refers to Columbia's "off-peak" firm service.[212] And Tejas suggests that a short-notice service priced between no-notice and traditional service might prove adequate for many customers.

Destec suggests that the Commission require an off-peak firm transportation service that is subject to interruption to provide no-notice transportation.

The Commission clarifies that the pipelines may offer transportation services in addition to no-notice and traditional firm transportation services.

13. Costs

The Industrial Groups argue that, on rehearing, the Commission should specify that all costs, direct or indirect, of providing no-notice service must be recovered in the rates for that service. The matter of the appropriate costs to be allocated to no-notice transportation will be addressed by the Commission

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212. Columbia Gas Transmission Corp., 54 FERC ¶ 61,226.

in the restructuring proceedings. As required by section 284.14(g) of the regulations, the pipeline must file tariff provisions implementing no-notice transportation service, with separately identified cost components.

14. Instantaneous Service

Gas Company of New Mexico asks the Commission to require pipelines to provide instantaneous delivery service that "would permit a shipper 'instantaneously' to schedule and deliver additional gas without waiting the 1-2 day period generally required by pipeline scheduling procedures."[213] The Commission denies Gas Company of New Mexico's request. While the Commission is requiring pipelines to provide instantaneous transportation service (see 18 CFR 284.14(b)(vii)), it is not mandating any change to pipeline scheduling and delivery requirements for traditional open access transportation service. Gas Company of New Mexico also asks the Commission to require pipelines to provide "instantaneous service" whenever (1) immediate action is required to avoid overpull or similar penalties, and (2) it would not be possible to schedule additional gas in time to avoid the problem. It adds that instantaneous service is a necessary adjunct to no-notice service and like no-notice service should be mandatory. Pipelines must provide instantaneous transportation service (see 18 CFR 284.14(b)(vii)) but, in the case of traditional open access transportation service this is only after the shipper's gas has been scheduled and delivered to the pipeline for transportation pursuant to its tariff requirements. The relationship between instantaneous service and no-notice service must be addressed in the restructuring proceedings.

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213. Petition at 14.

Appendix C

E. Storage

Order No. 636 amended § 284.1(a) of the Commission's regulations to define transportation as including storage. This means that pipelines must offer their customers firm and interruptible storage on an open-access, contract basis. Order No. 636 stated that pipelines can retain storage capacity downstream of the place of unbundling solely to fulfill their obligations with respect to system management (load balancing) and no-notice transportation. In addition, a pipeline can retain some storage capacity upstream of the place of unbundling in order to perform its sales service as follows:

> The allocation of this capacity between the pipeline, for use to make sales, and others, of course, must be done on a nondiscriminatory basis and the costs associated with the upstream storage capacity allocated to the pipeline must be recovered by the pipeline solely as part of its market-based sales rate. In addition, the pipeline must subject itself to all tariff terms and conditions applicable to holders of firm upstream storage capacity (*e.g.*, injection and withdrawal requirements).[214]

1. Allocation of Downstream Storage Capacity

Order No. 636 stated that the method for allocating downstream storage capacity should be addressed in the restructuring proceeding. Order No. 636 only required storage capacity to "be allocated on an even, nondiscriminatory basis

214. Order No. 636 at p. 30,427.

among all shippers without regard to the seller of the gas."[215] Order No. 636 also stated that "[a]ny allocation of storage capacity, however, must take into account pipeline capacity needs for load balancing and system management and the need to reserve some level of storage capacity for the pipeline or *for shippers in connection with the pipeline's no-notice transportation service.*[216]

Numerous petitioners argue that current bundled sales customers should have priority in the allocation of storage to maintain their level of maximum daily entitlement to service.[217] Memphis Light refers to the queue exemption for conversions from firm sales to firm transportation under Section 284.10(c) of the Commission's regulations.[218] The APGA maintains that sales customers with "eligible firm sales service agreements" have automatic rights to storage now that it is defined as transportation. The APGA adds that Section 284.10(c) should be revised and expanded to include those sales customers without "eligible firm sales service agreements." Colorado Springs argues that the right to storage for current sales customers should be on an individual storage facility basis. Southern Indiana

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215. *Id.*

216. *Id.* (emphasis added).

217. Illinois Commerce Commission, Memphis Light, Gas and Water (Memphis Light), Rochester Gas, Citizens Gas, City of Colorado Springs, Colorado (Colorado Springs), Illinois Power, Columbia Gas Distribution Companies, APGA, Citizen Action, Indiana Gas, Alabama Gas, UGI , City Gas, United Distribution Companies , Brooklyn Union, and Questar.

218. See Order No. 436 at p. 31,516-517. Section 284.10(c) provide firm sales customers with "eligible firm sales service agreements" with the right to convert to firm transportation service under Part 284.

asserts that the splitting of storage will render it meaningless.[219] ANR contends that the preemptive right to storage should not be tied to no-notice service and that "on an integrated storage network such as ANR's, individual customers should not be permitted to choose which particular storage field the pipeline will utilize to render storage service to them" in order to "avoid a lowering of the overall storage capacity available to the market."[220]

The Commission clarifies that current bundled firm sales customers have a priority right to the storage necessary to maintain their level of maximum daily entitlement to service. This is whether or not they elect no-notice transportation service. This right will enable pre-Order No. 636 customers buying gas under a small customer rate schedule to obtain storage needed to maintain their level of maximum daily entitlement in combination with the transportation service they elect whether it is no-notice or regular firm transportation. APGA's arguments about Section 284.10(c) are, therefore, moot. The actual allocation of storage facilities is a matter for the restructuring proceedings.

The Northern Distributor Group, Northern Illinois Gas, and Illinois Power argue that customers that have already converted should be entitled to storage on the same footing as customers converting under Order No. 636, without paying a premium. Northern Illinois Gas adds that system users should have priority over gas sellers for additional capacity. The Commission concludes that previously converted customers should not be entitled to storage on the same footing with customers converting under Order No. 636. This is because the customers that

219. Columbia Gas Transmission Corp., 53 FERC ¶ 61,366 (199).

220. Petition at 19, 20.

converted earlier were able to do so without storage to meet their needs. If storage is available after converting customers elect their storage levels, the pipeline must offer and allocate the remaining storage among all its shippers on a non-discriminatory basis. That is, current system users will have no priority over new transportation customers for additional storage capacity that is not selected by converting customers.

2. Upstream Storage

Order No. 636 provides that pipelines may retain storage capacity upstream of the place of unbundling to support their unbundled sales service.[221]

NGSA argues on rehearing that there is no justifiable basis for allowing pipelines to reserve upstream storage capacity to support their sales services. NGSA includes within its argument all capacity upstream of the unbundling point. They argue that "[u]pstream storage is equally capable of giving pipeline sales service an unfair competitive advantage" for the same reasons that apply to downstream storage (such as seasonal price arbitrage, transmission capacity supplementation, flow regulations and balancing). They are concerned that a "pipeline can offer any transportation service upstream of this point *unequally* to advantage its sales service."[222] NGSA also states that "[i]f the Commission clarified on rehearing that all shippers had an equal opportunity to purchase rights on the upstream facilities, the unbundling point distinction would become benign."[223]

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221. Order No. 636 at p. 30,427.

222. Petition at 10.

223. *Id.*

On the other hand, Transco and Brooklyn Union argue that pipelines should able to retain some production area storage downstream of the place of unbundling to avoid gerrymandering the place of unbundling to retain storage for its merchant service, even though unbundling could occur at the wellhead. Both view this issue as appropriate for the restructuring proceedings.

The Commission adheres to the conclusion in Order No. 636that pipelines may retain a share of production area storage upstream of the point of unbundling to support sales at the unbundling point. As stated in Order No. 636, and *supra* with respect to upstream production area capacity, the pipeline must allocate capacity between it, for use to make unbundled sales, and others on a non-discriminatory basis, and the costs associated with upstream capacity must be recovered by the pipeline solely as part of its market-based rates. In addition, the pipeline must subject itself to all tariff terms and conditions applicable to holders of firm upstream capacity (*e.g.*, storage injection and withdrawal levels).

The Commission disagrees with Transco and Brooklyn Union because title must pass at the unbundling point and, therefore, the pipelines do not have gas to put into storage downstream of that point.

3. Existing Contract Storage Service

In Order No. 636, the Commission stated that "(a)ll current holders of storage capacity will retain that capacity under current contractual provisions."[224]

CNG states that it does not intend to reduce its customers'

224. Order No. 636 at p. 30,427.

contract storage capacity under current contractual provisions. However, CNG states that it must have the ability to adjust existing storage operational protocols (*e.g.*, storage injection and withdrawal schedules) to reflect the current status of its system operations as more customers became contract storage customers. It adds that without that ability, it might have to reduce aggregate available storage capacity.[225]

The Commission's intent was that current contract storage customers retain their full right to capacity as specified in their contracts. The Commission did not mean to infer that the terms and conditions associated with their rights could not be changed if they proved unreasonable in light of Order No. 636's requirements of no-notice transportation and open access contract storage. This, of course, is a pipeline specific matter and must be addressed in the restructuring proceeding.

4. Transportation Associated with Storage

ANR asks the Commission to clarify that certain associated transportation is, in effect, operated as an integral part of ANR's storage complex, and therefore should not be "unbundled" to avoid stranding of valuable storage capacity. ANR states that it currently provides open access storage on that basis. ANR maintains that the same principle governs storage released or assigned, that is, the released or assigned storage should be tied to any associated transmission capacity.[226] The Commission

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225. The various answers and responses filed in connection with CNG's clarification request are acceptedinto the record.

226. ANR further seeks clarification about whether the storage volumes contained in the storage fields at the time of the release or assignment are

(Cont'd)

believes that this matter should be addressed in ANR's restructuring proceeding.

5. Storage Fields Disconnected From System

ANR states that it "owns certain storage fields that are physically disconnected from its system, but gas is moved to and from those storage facilities by means of transportation and exchange agreements with third party pipelines."[227] It argues that it should be to able treat these arrangements as an "integrated storage network"[228] to avoid "disynchronized allocations of storage, transmission and related transportation and exchange agreements [which] would render the operational continuity of the pipeline network into a meaningless state. . . ."[229] The Commission clarifies that storage disconnected from a system should be treated in the same manner as storage connected to the system and be allocated as determined in ANR's restructuring proceeding. However, the mere fact of disconnected storage cannot be used as a basis for discrimination with respect to related exchange or transportation agreements.

(Cont'd)
required to be released or assigned along with the storage. The Commission also believes that this matter should be addressed in the restructuring proceedings.

227. Petition at 18.

228. *Id.*

229. *Id.*

6. Leased Storage

ANR requests clarification that "storage capacity provided by leased facilities, and storage capacity provided by storage service agreements, should be treated in a similar fashion with directly owned storage facilities, as part of an integrated market area storage system."[230] The Commission clarifies that leased storage should be treated as if it were pipeline-owned storage.

7. Storage Combined with Other Services

In Order No. 636, the Commission stated that a pipeline is "required to offer the open-access storage on a basis that is unbundled and not in any way tied or linked to the storage customer's purchases of any particular type of sales service."[231] Brooklyn Union argues that the Commission should clarify that the rendition of storage service cannot be tied or linked to a customer's purchase of transportation or any other service offered by the pipeline. It maintains that some storage fields, *e.g.*, Leidy Storage Field, are connected to several pipelines. The Commission agrees that as a general matter pipelines may not tie services. Whether transportation and exchange arrangements can be packaged with the storage service is an issue to be resolved in each proceeding and will depend upon the configuration of the facilities and other operational factors. If, for example, there is no other way to get the gas into or out of a particular storage facility than through a particular transmission lateral, then it may be reasonable to combine the services.[232]

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230. Petition at 19.

231. Order No. 636 at p. 30,426.

232. Tennessee Gas Pipeline Co., 59 FERC ¶ 61,045 (1992).

Appendix C

8. Storage Reporting

In Order No. 636, the Commission instituted semi-annual reporting requirements with respect to the new open-access storage. The Independent Petroleum Association of America and Cooperating Associations (IPAA) states that more frequent reports are required and requests that each pipeline update the Section 284.106(g) data on a weekly basis and post such report on its electronic bulletin board.

Llano, Inc. (Llano) a pipeline providing Section 311 transportation, argues that semi-annual reporting is not needed in light of the monthly storage data collected by the EIA. It further contends that the required data is commercially sensitive and that the reporting requirements on small intrastate systems is not cost justified.

The Commission concludes that it is appropriate to require semi-annual reporting for all pipelines providing storage. This coincides with the injection and withdrawal cycles for storage activities. Further, the Commission in sections 284.8(b)(3) and (4) and 284.9(b)(3) and (4) of the regulations is requiring pipelines to post the availability of capacity in storage fields on the EBB. The precise nature of the information is to be developed in the restructuring proceedings. As the Commission gains experience, it may revisit this issue to determine whether more or less reporting is needed.

The Commission notes that the EIA does not collect data by individual customer nor does it collect rate and revenue data. Further, the information to be reported to the Commission on an semi-annual basis is similar to that currently reported by intrastate pipelines on an individual transaction basis for

transportation services subject to Part 284, Subpart C. In addition, the Commission will consider individual requests for waiver from the reporting requirements.

Llano argues that the Commission erred by not providing notice of the new semi-annual storage reporting requirements for intrastate pipelines. The Commission disagrees. First, the Commission requires reporting for transportation and storage that is now transportation so storage reporting is merely an aspect of transportation reporting. Second, even if considered a new reporting requirement, it is intimately connected with the authorization for intrastate pipelines to provide open access, contract storage to which Llano does not object.

F. Market Centers

In Order No. 636, the Commission adopted new regulations, Sections 284.8(b)(5) and 284.9(b)(5), which prohibit any provision in a pipeline tariff that would inhibit the development of market centers. The Commission believes that inter-pipeline market centers will enhance the efficient operation of the natural gas market and aid competition by creating markets where gas sellers from different production areas can meet gas purchasers from different market areas using different pipelines. Section 284.1(c) defined market centers as "an area where gas purchases and sales occur at the intersection of different pipelines."

Peoples Gas argues that the Commission should expand its definition of market center to include market-area in-line transfer points or areas on individual pipeline systems where title can passbetween buyers and sellers.

Natural Gas Clearinghouse asks the Commission to amend

the market center definition to recognize that "market centers" already exist at both interconnect and non-interconnect points on individual pipeline systems, *e.g.*, at pooling points and plant outlets, as can be seen by a quick review of the "Index" prices published by various trade press publications."[233] Natural Gas Clearinghouse suggests the following definition of market center.

> §284.1(c) Market center means an area where gas purchases and sales occur, for example, at the intersection of different pipelines or at recognized aggregation areas or pooling points on a specific pipeline.[234]

The Commission will not expand its definition of market center because it is not necessary to achieve the Commission's goal of not inhibiting the development of areas where purchases and sales of gas can occur. For example, the Commission, as stated in Order No. 636, will not permit actions that inhibit the development of pooling areas. While pooling areas and market centers are different concepts, title transfers may occur at pooling areas around the production areas.[235] However, the Commission will not resolve the in-line transfer issue until it has a specific proposal before it.

G. Pooling Areas

In Order No. 636, the Commission stated that it will not mandate production area pooling areas on individual pipelines

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233. Petition at 14.

234. *Id.*

235. Order No. 636 at p. 30,428.

for the aggregation of supplies by all merchants. The Commission did state, however, that it will not permit actions that inhibit the development of pooling areas.

Natural Gas Clearinghouse states it is willing to address the pooling area issue in the individual restructuring proceedings "*[p]rovided*, however, in order to provide substance to the Commission's requirement that pipelines allow for flexible receipt and delivery points, the Commission should clarify that each pipeline must provide shippers with a workable means to aggregate supplies and markets and should affirmatively state the implementation of pooling or paper pooling is one way to satisfy this requirement."[236]

As the Commission stated in Order No. 636, it is not mandating pooling areas. However, the Commission will not permit any actions that inhibit their development. Pipelines should work with shippers to develop a workable means to aggregate supplies. This is a matter to be considered in the restructuring proceedings. For example, in Order No. 636, the Commission stated that pipelines should consider entering into "operational balancing agreements" with other gas merchants to permit them to balance, in the aggregate, for all of their gas purchasers shipping on the pipeline.

H. Flexible Receipt and Delivery Points

Order No. 636 modified the Commission's policies with respect to flexible receipt and delivery points to provide for more flexibility. Order No. 636 first provided that pipelines must give firm shippers flexible delivery points in the distribution areas.

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236. Petition at 13 (emphasis in original).

This means that firm shippers will have the right to change firm delivery points and to use other delivery points on a interruptible basis without losing their priority for firm service.

Order No. 636 also expanded shippers' rights with respect to flexible receipt and delivery points outside the production area receipt points and inside the distribution area delivery points by including the right to receive gas from any person at any place on the system and the right to deliver gas to any person at any place on the system on a firm basis, with the flexibility to change firm receipt and delivery points and to use all delivery points on an interruptible basis.[237]

In addition, Order No. 636 stated:

> Of course, receipt and delivery points must be within the firm transportation capacity to which the shipper is entitled, and for which it pays. So, for example, an LDC in a downstream region of the country could arrange to deliver gas to an LDC or an industrial in an upstream region, but conversely an LDC in an upstream region could not arrange for delivery in a downstream region.[238]

That is, flexibility is allowed only "within the path" of the shipper's service.

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237. Order No. 636 at p. 30,429.

238. *Id.*

Appendix C

1. Opposition to Flexible Receipt and Delivery Points

Atlanta Gas argues that the Commission "should eliminate its policy mandating flexible receipt and delivery points . . . [and] [t]o the extent flexibility is appropriate, it should be the subject of negotiation among affected parties, with appropriate conditions placed on the exercise of flexible receipt and delivery point rights."[239] Atlanta Gas maintains that the Commission's policy will result in destructive, often one-sided, competition by downstream LDCs and may subject LDCs utilizing flexible delivery points in other states to NGA regulation by transporting in interstate commerce rather than local distribution.

The Commission believes that flexible receipt and delivery points will promote maximum efficient usage of the pipeline system, are necessary to the development of market centers and to the achieving of a meaningful capacity releasing program. Thus, flexible receipt and delivery points should promote competition in the natural gas industry to the benefit of gas consumers.

The Commission does not believe that an LDC, by shipping gas to a delivery point outside its home state subjects itself to NGA jurisdiction. The LDC is not a transporter of gas in interstate commerce because it is not operating the system or controlling access by others any more than under existing transportation arrangements without flexible delivery points.[240]

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239. Request for Rehearing at 14.

240. *Cf.* Algonquin Gas Transmission Co., 59 FERC ¶ 61,032 (1992) and El Paso Natural Gas Co., 59 FERC ¶ 61,031 (1992).

2. Current Rights to Receipt and Delivery Points

Equitrans, Inc. (Equitrans) asks the Commission to clarify that prior Part 284 firm conversions are not terminated or existing firm receipt point capacity reallocated in order to make accommodations for later-in-time conversions under Order No. 636.

CIG similarly asks for clarification that flexible receipt and delivery points do not require existing capacity holders at the changed receipt and delivery points to be "bumped" in order to accommodate a change.

INGAA requests the Commission to clarify that flexible delivery points are subject to availability. It states that "if, for example, the system is fully booked, the pipeline should be allowed to grandfather existing delivery points, or provide flexibility on an as needed basis."[241]

Northern Illinois Gas asks the Commission to promulgate specific guidelines with respect to the use of flexible delivery points within a distribution area. For example, it maintains that the use of a flexible delivery point should never be able to preempt or require curtailment of a preexisting firm delivery point.

The Commission clarifies that current shippers that retain their firm capacity rights during the restructuring proceedings also retain their priorities at designated receipt and delivery points and may not be bumped, preempted, or curtailed under the flexible receipt and delivery point policy.

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241. Petition at 11.

Appendix C

3. Nature of Flexible Receipt and Delivery Points

Hadson states it is concerned about the priority principles governing flexible receipt and delivery points. It perceives a contradiction in the Commission's statement that firm shipments may displace interruptible shippers on reasonable notice and the statement that alternate firm points may be used on an interruptible basis.

Peoples Gas argues that the Commission "should specify that service in the distribution area to a 'flexible' or alternate delivery point designated by a firm customer is inferior to service rendered to another firm customer that uses the same delivery point as a primary delivery point, but superior to other interruptible services at that delivery point."[242]

Southwest Gas contends that the Commission "must clarify that the ability to designate delivery points on a firm basis under a flexible delivery point policy must be limited by the availability of [firm] capacity at the designated delivery points."[243]

The Gas Company of New Mexico contends that firm service to a primary delivery point should always have a priority over firm service to a flexible delivery point.

The Commission clarifies that firm shippers' use of designated alternate/flexible delivery points is subject to the rights of firm shippers using those points as primary delivery points but is superior to the rights of interruptible shippers to

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242. Petition at 13.

243. Petition at 2, 3.

those points.[244] Hence, Order No. 636 was correct in describing the use of alternate/flexible delivery points as interruptible inasmuch as those rights are, as stated, inferior to primary firm delivery points.

4. Reasonable Notice — Priority

Cincinnati Gas asks the Commission to reinforce the absolute priority of firm transportation over interruptible transportation. It adds that the Commission "should make it clear that the 'reasonable notice' required for purposes of bumping interruptible transportation is to be defined in a manner that maximizes the priority of firm capacity."[245]

The Commission agrees that firm transportation has priority over interruptible transportation but cannot establish a generic standard for reasonable notice of bumping interruptible transportation.

ANR asks the Commission "to clarify that delivery point flexibility should not be mandated on a daily basis, and that the parties are free to develop the rules governing delivery point flexibility in their individual restructuring dockets."[246] It states

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244. Peoples Gas asks the Commission to "make clear that use by existing firm customers of existing capacity at distribution area delivery points, including the ability to shift firm entitlements from one division or plant to another, will not be adversely affected." Petition at 12. The Commission clarifies, but only to the extent that the existing firm customers bump interruptible and not firm shippers with primary rights.

245. Petition at 49.

246. Petition at 10.

that this is necessary to prevent the dramatic multiplication of operational difficulties that would be caused by the ability to switch no-notice delivery points on a daily basis.

The Fuel Managers Association argues that pipelines should be required to provide flexibility in scheduling receipt and delivery points up to the maximum technical ability if high technology equipment is available, or, if it is not, to make best efforts to provide the maximum flexibility in shipper scheduling.

The Commission endorses the idea that each pipeline should provide for maximum flexibility with respect to receipt and delivery point scheduling in light of the reasonable operational requirements of the pipeline. The Commission directs the parties to fashion procedures governing receipt and delivery point flexibility in the individual restructuring proceedings. If a pipeline, such as ANR, wishes to limit flexibility, it must demonstrate in that proceeding that the limitation is a reasonable operational limitation.

5. Penalties

The Fuel Managers Association maintains that there should be no scheduling penalties for changing scheduled receipt and delivery point locations, volumes, and gas delivery, because FT shippers pay SFV rates which already reflect those charges.

Northern Illinois Gas also argues that a pipeline should not be able to impose a penalty if the LDC rearranges its takes among delivery points so long as the takes within an operational zone are equal to confirmed nominations. It states there is no operational reason to tie specific transportation supplies to specific delivery points within an integrated service area.

Appendix C

Issues involving the provisions governing the use of receipt and delivery points, including appropriate penalties, must be addressed in the restructuring proceedings. The purpose of penalties is to inhibit abusive behavior and so they need not be cost based. At the same time, there must be some valid operational reason for imposing penalties on changes in volumes to delivery points within an interrelated service area.

6. Downstream Delivery Points/Upstream Delivery Points

Southwest Gas argues that a shipper should only be able to designate delivery points at the same points or points upstream of the shipper's own delivery points.

The Gas Company of New Mexico argues that the Commission should deny flexible delivery points to all shippers or provide for upstream shippers to have downstream delivery point flexibility, or, if not, make the downstream shippers pay a higher rate to reflect the higher value of their services.

Brymore suggests that the Commission expand delivery point capabilities to include out-of-path points on a secondary basis to expand the value of upstream capacity. Brymore adds that: "Pipelines can (and should) be kept whole by charging an incremental rate to take gas from the most downstream in-path point to the ultimate delivery point. This charge should be equal to the difference in the demand charge components that would be applied to the reassigned capacity plus the difference in the applicable firm commodity rates."[247]

Hadson argues that Order No. 636's language could be read

247. Petition at 17.

as limiting rather than increasing flexibility. Hadson asks the Commission to clarify that firm shippers' rights to flexible receipt and delivery points "include the right to receive gas from any person at any place on the system, and the right to deliver gas to any person at any place on the system[,]"[248] without the limitation on upstream shippers using downstream delivery points.

The Commission adheres to the discussion in Order No. 636 with respect to flexible receipt and delivery points along the mainline; that is, between the place of unbundling, including pooling areas, and the place of primary delivery, *e.g.*, the city-gate or distribution areas. Downstream shippers may designate upstream receipt and delivery points. This is because the downstream shipper is using part of the capacity which it has reserved. However, upstream shippers may not designate downstream receipt and delivery points because they have not reserved or paid for that capacity. If the upstream shipper wants to expand its delivery point capability to include "out-of-path" delivery points, it must obtain that capacity from the pipeline or from another shipper via capacity releasing. But an upstream shipper has no right to downstream capacity solely because it already is a firm shipper.

New England Power argues that shippers with upstream delivery points within a zone should be able to select downstream delivery points within the same zone as well as vice versa. It states that operational concerns can be met by making the downstream service an interruptible service.

The Commission agrees with New England Power that shippers with upstream delivery points within a zone can select

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248. Petition at 14.

downstream delivery points within the same zone and that operational concerns can be met by making service to the downstream delivery point interruptible. This is consistent with the general principle that controls here: a shipper gets flexibility in receipt and delivery points for the part of the system for which it pays a reservation charge. Thus, if a pipeline has zone rates, a shipper gets flexibility within its zone. The appropriate rate for the use of a downstream delivery point within a zone should be addressed in the restructuring proceedings. Hadson argues that shipments "within the [contract] path" should be priced no higher than the FT usage charge for the actual path used. [249] The Commission agrees with Hadson and so clarifies because the usage charge includes only variable costs.

7. Distribution Area Limitation

In Order No. 636, the Commission required pipelines to permit firm shippers to designate flexible delivery points in their distribution areas in the same manner as they designate flexible receipt points in the production areas. Hadson states that the Commission has ignored non-LDC business enterprises that take delivery of gas but have no distribution areas.

The Commission agrees with Hadson and clarifies that it used "distribution areas" in a broad sense, and not as a term of limitation.

8. Section 7(c) shippers

New England Power and Transco argue that shippers receiving transportation service under individual section 7(c) certificates should have the same rights to flexible receipt and

249. Petition at 6.

delivery points as Part 284 shippers. The Commission disagrees. Flexible receipt and delivery points are part of Part 284 transportation. If New England Power (or similarly situated shippers) wants flexible receipt and delivery points, it should convert to Part 284 transportation.

9. Interruptible Transportation

Natural argues that the Commission should permit delivery point flexibility with respect to interruptible transportation. The Commission will permit interruptible transportation flexibility so long as the capacity exists.

10. New Facilities

Southern requests clarification that the flexible delivery point policy of Order No. 636 does not require the construction of delivery point facilities — the "new mandate only refers to available capacity at existing facilities as is the way flexible receipt points are administered on pipelines' systems."[250] Without addressing the merits of any particular case, the Commission clarifies that the flexible delivery point policy by itself does not require the construction of new facilities. However, to the extent pipelines construct new receipt and delivery point facilities, they must do so on a nondiscriminatory basis.

11. Flexible Delivery Points-Pooled Capacity

NIEP asks the Commission to amend the flexible delivery point provisions "to specifically permit such flexibility within the LDCs' pooled capacity, even across pipeline systems. It maintains that LDCs "may need to switch delivery points on a

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250. Petition at 9.

pipeline system, as well as switch pipeline systems, within the pooled arrangement on a periodic basis in order to access changing gas supply services."[251] The Commission regards the right to use of flexible delivery points as applicable only to shippers with capacity on the pipelines. A shipper receives flexibility in its receipt and delivery points for the part of the system for which it pays a reservation charge. Hence, shippers that pool capacity must each arrange for flexible delivery points on the pipelines on which they ship.

12. Bypass

Atlanta Gas asks the Commission to clarify that its discussion of flexible receipt and delivery points in Order No. 636 is not to be read as instituting a mandatory bypass policy for end users to tap into pipelines. The Commission is not instituting a mandatory bypass policy in Order No. 636. But pipelines must permit end users with firm transportation rights under Part 284 to use flexible delivery points.

13. Exemption

Southwest Gas asks the Commission to expressly exclude El Paso from any flexible delivery point requirement because under El Paso's system of operation, there is insufficient basis owing to constraint points to adopt a flexible receipt point policy. The Commission believes that issues involving El Paso's constraint points and flexible delivery points must be addressed in El Paso's restructuring proceeding.

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251. *Id.*

Appendix C

I. Curtailment

Several of the parties in their rehearing requests contend that Order No. 636 is in error in not requiring that capacity allocations during periods of capacity curtailment be implemented on an end-use rather than on a *pro-rata* basis.[252] Generally, these parties argue that the high-priority, end-use categories established by Title IV of the Natural Gas Policy Act (NGPA),[253] apply to capacity curtailments as well as supply curtailments. APGA, Brooklyn Union, the Fertilizer Institute, the State of Michigan, Rochester Gas, and Washington Gas maintain that the operative statutory language in Title IV applies to curtailment of all natural gas "deliveries" and does not distinguish between the curtailment of deliveries caused by supply shortages as opposed to the curtailment of deliveries caused by capacity constraints. APGA argues that Congress did not specifically apply the Title IV priorities to capacity curtailments because pipeline services at the time of enactment of the NGPA were bundled. Similarly, Rochester Gas contends that the NGPA was passed in a different regulatory environment and while the Commission has changed the regulatory scheme, this does not eliminate the Congressional intent expressed in Title IV that deliveries of gas to high-priority end-users be protected during curtailment. APGA, Citizens Gas, Rochester Gas and Washington Gas further maintain that mandatory unbundling of pipeline sales service combined with *pro-rata* capacity curtailment results in a degradation of service by depriving pipeline sales customers of their Title IV curtailment priority in the event of a capacity curtailment.

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252. APGA, Brooklyn Union, Cincinnati Gas, Citizens Action, Citizens Gas, the Fertilizer Institute, the State of Michigan, Rochester Gas, and the Washington Gas Light Company (Washington Gas).

253. 15 U.S.C. §§ 3391-94.

APGA, Brooklyn Union, the Fertilizer Institute, and Washington Gas further argue that Title IV was enacted as a result of Congressional concerns over the effects of natural gas cut-offs to agricultural and other high-priority users and that from the end-user's standpoint supply and capacity curtailments are the same in their effects. Thus, these parties conclude that the Congressional concerns regarding supply cut-offs pertain equally to capacity caused cut-offs and that Congress intended that Title IV apply equally to supply and capacity curtailments. APGA also argues that Congress in Title IV required the Commission to protect high-priority users to the "maximum extent practicable" and that such policy applies equally to capacity and supply curtailment. Brooklyn Union further asserts that it is illogical to conclude that Title IV does not apply to the new national transportation network fostered by other sections of the NGPA.

The Commission is not persuaded by these arguments to depart from its interpretation of the inapplicability of the Title IV end-use priorities to capacity curtailments. The Commission has interpreted Title IV of the NGPA in this manner since the enactment and initial implementation of the NGPA[254] and since that time has consistently reiterated its position that Title IV applies only to curtailment by pipelines of natural gas deliveries caused by supply shortages.[255] Furthermore, the Commission has also consistently rejected arguments similar to those advanced by the parties in this proceeding to the effect that Title

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254. *See, e.g.*, Order No. 29-C, FERC Stats. & Regs., Regulation Preambles 1977-1981, ¶ 30,092 (1979).

255. *See, e.g.*, Order No. 436, FERC Stats. & Regs., Rep. Preambles 1982-1985, ¶ 30,665 (1985).

IV applies to both capacity and supply curtailments.[256] Moreover, we believe that more recent expressions of Congressional intent regarding the structure and operation of the natural gas industry, *i.e.*, the Decontrol Act,[257] support the Commission's curtailment policies as expressed in Order No. 636.

Again, it is the Commission's view, based upon the language of the NGPA itself, the circumstances surrounding the enactment of the NGPA, the legislative history of the NGPA and subsequent court opinions that application of the Title IV end-use priorities to capacity curtailments (that is, transportation) was neither intended nor envisioned by the Congress. First, it is beyond dispute that the NGPA was enacted to remedy the natural gas supply shortages facing the nation which became critically apparent in the mid-1970's.[258] Title I of the NGPA was intended to provide investors with adequate incentives to develop new sources of gas supply. Title II of the act was intended to ameliorate the immediate impact of these incentive prices on certain classes of natural gas users. Title III of the Act was intended to break down the existing barriers between the interstate and intrastate natural gas markets, so that formerly intrastate natural gas supplies could flow freely into the national market place to alleviate the natural gas shortage in the interstate market. In addition, Title III vests in the President a broad array of powers to respond to natural gas *supply* emergencies. In sum, the policy provisions of the NGPA were all enacted in response

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256. *See, e.g.*, Order No. 29-C, *supra*; Order No. 436-A, FERC Stat. & Regs., Regulation Preambles 1982-1985, ¶ 30,675 (1985).

257. Pub. L. No. 101-60, 103 Stat. 157 (1989).

258. *See, e.g.*, Process Gas Consumers Group v. United States Department of Agric., 694 F.2d 728, 738 (D.C. Cir. 1980).

to the need to increase the *supply* of natural gas available to fill the nation's energy needs. On the other hand, the issue of pipeline capacity constraints was not part of the Congress' remedial action in its enactment of the supply-oriented NGPA. It is in this context that the petitioners' arguments regarding the intended scope of the applicability of Title IV must be viewed.

The petitioners' major argument is that the operative language of Title IV speaks in terms of "deliveries" of natural gas, *i.e.*, "curtailment of deliveries for such use,"[259] and that no specific distinction between curtailment of deliveries due to supply shortages and those due to capacity constraints is made. It is our view that, in the light of the immediate purpose of the NGPA to provide incentives to prevent gas supply shortages, the petitioners read into the term "deliveries" an application that was not intended by the Congress. At the time the NGPA was enacted, the curtailment plans on file with the Commission generally governed only pipeline sales curtailments resulting from gas supply shortages, not capacity limitations. This resulted from the fact that the Federal Power Commission's (FPC) curtailment policies and regulations from their inception were intended to deal with the "allocation of priorities and rationing of this limited supply of natural gas" available to be sold by interstate pipelines occurring during "gas shortages".[260]

Under the FPC curtailment rules, interstate pipelines were only required to file supply curtailment plans covering natural gas sales and were not required to file capacity curtailment plans

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259. *See, e.g.*, 15 U.S.C. §§ 3391(a), (a)(1).

260. Louisiana Power and Light Co. v. FPC, 483 F.2d 623,626 (5th Cir. 1973). *See* also, Pacific Gas & Electric Co. v. FPC, 506 F.2d 33,35 (D.C. Cir. 1974); State of North Carolina v. FERC, 584 F.2d 1003,1007 (D. C. Cir. 1978).

covering transportation. Moreover, the FPC's policy statements requiring pipelines to file these sales curtailment plans, like the NGPA, also used the operative term "deliveries" as opposed to "sales" or "transportation".[261] Thus, it is likely that the choice of the operative term "deliveries" in Title IV was chosen to correspond to the same operative term found in the existing FPC required supply curtailment plans. This view is in accord with the stated intent of the Congress that for purposes of implementing Title IV "the Commission is instructed to reopen curtailment plans that are already in effect under the NGA only to the extent necessary to adjust those plans to bring them into conformity with the new curtailment priority schedule."[262] Had Congress intended also to cover gas only transported by the pipelines or to cover capacity curtailments, then nearly all of these plans would have had to be reopened.

Further, the broad term "deliveries" covers sales for resale as well as transportation for direct sale, both circumstances subject to the FPC's curtailment jurisdiction and pipeline curtailment plans. Moreover, this view of the use of the term "deliveries" is also in accord with Congressional statements of its understanding of the definition and purpose of curtailment plans as expressed in the legislative history of related energy legislation, *i.e.*, the Public Utilities Regulatory Policies Act of 1977.[263] As stated in *Process Gas Consumers v. United States Dept. of Agriculture*:

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261. *See, e.g.*, Order No. 467, 49 FPC 85 (1973) ("priorities-of-deliveries by jurisdictional pipelines during periods of curtailment"), Order No. 467-B, 49 FPC 583 (1973) ("initial priorities to be followed by jurisdictional pipeline companies during periods of curtailed deliveries").

262. Joint Explanatory Statement of the Committee of Conference, Title IV, Section 401, I FERC Stats. & Regs. ¶ 3101 at p. 3121 (1978).

263. Pub. L. No. 95-617.

Appendix C

Since the advent of natural gas scarcities in the early seventies, regulated interstate pipelines have been required to establish elaborate curtailment plans detailing which of their customers will get how much gas in what priority in times of short supply. In Congress' own words:

> Curtailment plans establish priorities for the delivery of natural gas when supplies are insufficient to meet contract demand. . . .
>
> H.R. Rep. No. 1750, 95th Cong., 2d Sess. 112-13 (1978), U.S. Code Cong. & Admin. News 1978, p. 7846.[264]

Thus, as the agency charged with interpreting the NGPA, the Commission remains of the opinion that in enacting Title IV, the Congressional intent was to assure that gas supplies for essential agricultural and the other specifically enumerated high-priority end-users would be afforded the highest priorities in then existing pipeline supply curtailment plans in the event of a shortage of the gas supplies sold by interstate pipelines. The Commission further believes that it would be in error for it to infer that if Congress had in fact addressed and considered the then hypothetical issue of capacity curtailments, Congress would have mandated the same end-use curtailment method to be applied to capacity curtailments as that envisioned for supply curtailments. As indicated below, capacity curtailments present problems and issues distinct from those presented by supply

264. 694 F.2d. 728, 772 (D.C. Cir 1980) (Wald, dissenting on other issues).

curtailments in the context of unbundled, open access transportation, and in the Commission's judgement are not suited to resolution by imposition of end-use priorities.

The petitioners present a literal reading of Title IV of the NGPA, viewed apart from the legislative history, contemporaneous industry conditions and historical context in which it was enacted. Even if this view can be squared with a plausible application of the literal words of the statute, the Commission does not believe it can be reconciled with the context in which the NGPA was enacted or with more recent expressions of Congressional intent. For instance, the petitioner's contention that the Title IV end-use priorities apply to pipeline capacity curtailments creates a conflict with the more recent expression of Congressional intent embodied in the Decontrol Act. The Decontrol Act "finished off" the then already nearly complete natural gas decontrol process initiated in the NGPA.[265] The Decontrol Act expresses Congressional recognition of a completion of the "transition from the highly controlled, shortage-beset gas industry . . . to today's substantially decontrolled market."[266] It also recognizes the creation by the Commission of "a competitive gas purchasing and transportation market," which in the opinion of Congress would minimize the instability in the natural gas markets which was characteristic of what the Congress acknowledged as being an antiquated regime of stringent regulatory controls.[267] The Congress further found that the Commission's open-access pipeline initiatives had created more competition in the interstate pipeline industry

265. H. Rep. No. 29, 101st Cong. 2d Sess., at p. 2 (1989).

266. *Id.* at 3.

267. *Id.*

and had brought lower prices to all consumers, including captive residential consumers.

Thus, while the Decontrol Act did not deregulate gas pipelines, the Act is a clear endorsement of the benefits of a pro-competitive regulatory scheme for national gas supplies. Moreover, the Congress in enacting the Decontrol Act expressed its strong belief that the Commission's "current competitive open-access pipeline system [be] maintained" to ensure that captive customer's are not disadvantaged".[268] An integral part of the Commission's "current open-access" pipeline system was that firm, open-access transportation was not *required* to be allocated on a Title IV type end-use basis in the event of curtailment.[269] In addition, the Commission believes that the complexities inherent in end-use capacity curtailment plans and the fact that the Commission has never required capacity curtailments to be implemented on an end-use basis would, if

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268. *Id.* at 4.

269. *See, e.g.*, Order No. 436-A; *supra*, FERC Stats. & Reg. Preambles (1982-85) at p. 31,652. While the Commission has required open-access transportation to be curtailed on a *pro-rata* basis, the Commission has approved settlements which also provide differing degrees of end-use allocation. *See, e.g.*, Northwest Pipeline Corp., 39 FERC ¶ 61,109 (1983) (permitted establishment of curtailment priority for essential agricultural and high-priority uses in the absence of adverse comments); Florida Gas Transmission Co., 51 FERC ¶ 61,309 (1990) (curtailment by end-use permitted); United Gas PipeLine Co., 49 FERC ¶ 61,006 (1989) (end-use emergency relief permitted in context of a settlement). Curtailment issues must be considered in the RS proceedings and the parties in the RS proceedings may agree upon similar arrangements if they can be implemented in accordance with the restructured services of a particular pipeline. For the Commission to *require* such arrangements for all pipelines, however would severely undermine the principles of unbundled, open access transportation.

ordered generically, impose a significant regulatory burden. Thus, in the Commission's judgement the curtailment policies set out in Order No. 636 represent a proper reconciliation of the requirements of Title IV of the NGPA, the more recent statements of Congressional purpose expressed in the enactment of the Decontrol Act, and the policies underlying Order No. 636.

APGA, Brooklyn Union, and Citizens Gas also argue that not applying end-use priorities to capacity curtailment is inconsistent with the NGA and past Commission policy prior to the enactment of the NGPA. These parties contend that under the NGA the Commission's policy was that end-use curtailment was necessary because private contracts do not necessarily serve the public interest and that the rationale for protecting high-priority customers under the NGA is the same today as it was before. Citizens Gas maintains that the NGA requires assurance of reliable service to high-priority end-users. APGA similarly contends that the public interest under the NGA requires that high-priority end-users be protected from curtailment.

The Commission disagrees with the notion advanced by these parties that because in the 1970's the FPC found that the allocation of scarce gas supplies during curtailment was required to be based upon end-use principles, rather than private contractual arrangements, in order to protect the public interest that the Commission in the 1990's is now restricted to requiring an end-use methodology as the industry's exclusive allocation methodology during both supply and capacity curtailments. First, while it is correct, as the petitioners point out, that the courts have approved end-use as an appropriate consideration for purposes of pipeline supply curtailments,[270] the NGA does not

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270. *See, e. g.*, State of North Carolina v. FERC, *supra* 584 F.2d at 1012.

require that allocations of either supply or capacity during curtailment be made exclusively on the basis of end-use principles. Moreover, in the light of the changes in both the regulatory and legislative environment, as well as changes in the natural gas industry which have transpired since the 1970's, as discussed above, the Commission believes that the exclusive reliance on an end-use allocation methodology is not required to protect the public interest. The Commission believes that with deregulated wellhead sales and a growing menu of options for unbundled pipeline service, customers should rely on prudent planning, private contracts, and the marketplace to the maximum extent practicable to secure both their capacity and supply needs. In today's environment, LDC's and end-users no longer need to rely exclusively on their traditional pipeline supplier. Rather, to an ever-increasing degree they rely on private contracts with gas sellers, storage providers, and others; a more diverse portfolio of pipeline suppliers, where possible; local self-help measures (*e.g.*, local production, peak shaving and storage); and their own gas supply planning through choosing between an increasing array of unbundled service options. In addition, natural gas market conditions are now very different from the 1970's. In contrast to the chronic supply shortages of the 1970's, capacity and supply disruptions in the 1990's, if they occur at all, are likely to be infrequent and short-lived, largely as a result of the changes initiated by the provisions of the NGPA other than Title IV and the Commission's policies in Order Nos. 436 and 636.

Given the growing array of unbundled service options, which will be further promoted by Order No. 636, customers are increasingly free to choose different mixes of firm and interruptible pipeline services as well as different sellers, different receipt points, and different market centers or aggregation points. In making such choices, each customer will

assume different price and reliability risks. Requiring the generic allocation of pipeline capacity on the basis of end-use rather than *pro rata* based upon each customer's contractual choices would tend unfairly to protect those who took risks at the expense of customers who have undertaken the planning and greater cost of proceeding cautiously. Such a result would be neither just nor reasonable nor consistent with the unbundled, market-oriented gas industry, which both the Congress and the Commission have been encouraging. Accordingly, the Commission finds that neither the NGA nor the public interest require that the Commission on an industry wide basis today extend the end-use curtailment rules applicable to pipeline sales to interstate pipeline transportation, storage, or other services.

APGA, Laclede Gas Company (Laclede), and the State of Michigan argue that the issue of capacity curtailment methodologies aside, Order No. 636 does not adequately provide curtailment protection from supply shortages to high-priority end users. These parties contend that Order No. 636 defeats the purpose of the NGPA Title IV priorities during times of natural gas shortages. APGA and Laclede maintain that given the possibility of a failure of third-party gas supplies, reliance on third party sales makes protection from supply shortages difficult and that market based pricing will not adequately protect high priorities from supply shortages. Laclede argues that the Commission should require that a plan be in place to insure gas availability to high priorities in the event of a shortage in supply.

We disagree with these assertions that Order No. 636 fails to protect high-priority users from supply shortages. The Commission is of the view that the best protection from the specter of a future natural gas supply shortage is the promotion of an open and competitive wellhead market where all natural

gas suppliers are able to compete for gas purchasers on an equal footing, unhindered by the possession of any undue competitive advantage by any class of suppliers. By fostering this goal, Order No. 636 aims to ensure that the benefits of wellhead decontrol, including helping "to ensure adequate supplies of reasonably priced gas in the future"[271] will redound to the benefit of consumers of natural gas to the maximum extent as envisioned by the NGPA and the Decontrol Act.

Congress' judgement was that the best protection against, and remedy for, supply shortages was to allow the market to establish the price for gas. If supplies tighten, the price can rise which will stimulate new investment to bring new supplies to market. Since Congress mandated this course, beginning with the enactment of Title I of the NGPA, the industry has not experienced shortages beyond isolated, short-lived dislocation. By eliminating the undue competitive advantage inherent in pipeline bundled sales services and by establishing a pipeline rate structure under which all gas merchants will be able to compete in a national market without regard to fixed transportation costs included in usage charges, Order No. 636 will help to achieve Congress' intent in passing the Decontrol Act to "over time force the evolution of a set of lowest-cost producers" which "will yield lower prices and more abundant supplies".[272] Moreover, as we discussed above in regards to capacity curtailments, we believe that the imposition of the industry-wide, end-use supply curtailment scheme envisioned by the petitioners would be inconsistent with the market-oriented policies espoused by the Decontrol Act and given foreseeable supply conditions, would be an unnecessary regulatory burden.

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271. S. Rep. No. 39, 101st Cong., lst. Sess., at p. 2 (1989).

272. H.R. Rep. No. 29, *supra*, at p.7.

Finally, in the event of an unexpected and sudden *force majeure* supply shortage, Title III of the NGPA vests in the President ample authority to effectively assure that available gas supplies are allocated and transported to meet critical needs.

Several parties[273] assert the position that the Commission's direction to the parties, to negotiate and develop voluntary plans to deal with emergency shortages due to capacity constraints in the restructuring proceedings, is an abdication of the Commission's statutory responsibilities. APGA and State of Michigan argue that LDC's should not be penalized by having to pay high amounts to lower priority customers in order to be assured of being able to serve their high-priority loads. APGA, Citizens Action, and the State of Louisiana argue that the Commission must require that all pipelines include in their compliance filings an emergency exception from their *pro-rata* curtailment plans to provide gas to residential and small commercial users and to protect life and property in the event of curtailment. The Industrial Groups assert that all pipelines should implement plans to allow their customers to offer voluntary release of capacity for compensation during emergency situations. APGA further maintains that contractual provisions are an inadequate method for protecting human needs customers and other high-priority end users. In addition, the Industrial Groups state that while it supports *pro-rata* curtailment, that the Commission should prescribe specific allocation procedures rather than leaving the parties to negotiate such procedures. The State of Michigan also avers that the Commission has failed to explain the basis of the assertion in Order No. 636 that gas will continue to flow for heating without regard to *pro rata* curtailment plans.

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273. APGA, Brooklyn Union, Cincinnati Gas, State of Michigan, and Rochester Gas.

Appendix C

The arguments of the petitioners that object to developing curtailment plans and negotiating plans to implement voluntary contractual emergency supply and transportation arrangements in the restructuring proceedings are grounded on an incorrect premise, *i.e.*, that the NGPA and/or the NGA mandate that the Commission establish a specific set of procedures for end-use allocations applicable to all pipelines. As discussed above, in the Commission's view, this assumption is not accurate.

Order No. 636 allows the pipelines and their customers to develop a capacity curtailment plan in the restructuring proceedings under the general guideline that the result of such negotiations must be a tariff that sets out the pipelines' supply and capacity curtailment plans in sufficient detail to accommodate the interests of all shippers. The Commission believes that this is in accord with the principles underlying both the NGA and the NGPA. Moreover, such negotiated curtailment plans will result in systems of allocation and the development of voluntary, mutually beneficial, emergency contractual programs and procedures that are best tailored to the individual pipelines and the needs of their customers as expressed in the economic value, *i.e.*, price, which they are willing to pay either to the pipeline itself or, under private contractual arrangements, to other pipeline shippers, to assure that their demand for capacity on the pipeline will be satisfied in the event of curtailment. In this regard, the Commission endorses the suggestion of the Industrial Groups that pipelines include as part of their compliance filings plans to allow their customers to offer voluntary release of capacity for compensation during emergency situations, and encourages the development of similar suggestions which have been made in this proceeding.[274]

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274. *See, e. g.*, Technical Conference Tr. at 282-83.

Finally, as the State of Michigan points out, the Commission does expect that gas will continue to flow to those who need it for heating or other important needs, notwithstanding a pipeline's *pro rata* curtailment plan. The Commission's expectation is based on experience since the implementation of the NGPA, which shows that gas has always flowed according to the dictates of the market, *i.e.*, to the heat sensitive users who need it most and who are thus willing to pay the prevailing market price for it. It is because the Commission expects that these historical market forces will continue to direct gas supplies and capacity to heating and other important uses, that we have urged the parties to develop flexible tariff mechanisms, whether in the nature of special relief with compensation, voluntary contractual arrangements or some other device, which will allow pipelines and their customers in planning their operations to take into account and provide mechanisms for dealing with these contingencies.

Elizabethtown expresses the view that Order No. 636 should require customers receiving more than a *pro rata* share of pipeline gas during periods of shortage to pay compensation to customers who receive less than a *pro rata* share as a consequence. Rochester Gas maintains that compensation schemes can be developed in the pipelines' restructuring proceedings which can compensate low priority users whose gas is lost to high-priority users as a result of curtailment. In addition, Elizabethtown contends that Order No. 636 should require that a pipeline sales customer exhaust all of its alternative sources of supply before being eligible to receive a pipeline's sales gas supply under its curtailment priority.

The Commission's position on curtailment compensation plans is that the parties in the individual restructuring proceedings must explore the development of such schemes as

those suggested by Elizabethtown and Rochester Gas in the context of developing their individual curtailment plans and in the development of voluntary emergency contractual arrangements between shippers. However, the Commission believes that it would be contrary to the concept of the restructuring proceeding process and the negotiation and development of individually tailored curtailment allocation procedures and emergency mechanisms for it to mandate a generic compensation scheme. In addition, in its request for rehearing, Elizabethtown has not presented any argument to persuade the Commission to change its position that it is not appropriate to require high priority customers to exhaust other sources of gas supplies before being entitled to receive more than a *pro-rata* share of available pipeline supplies by application of the NGPA Title IV priorities to pipeline sales.

Tenneco claims that the provisions of Order No. 636 requiring parties in the restructuring proceedings to fashion their own curtailment plans constitutes an effective change in prior curtailment plans and policy which requires the preparation of an Environmental Impact Statement (EIS) prior to issuance of the Order.

The Commission is of the opinion that the issuance of the curtailment related provisions of Order No. 636 does not require the preparation of an EIS. First, the Commission has not changed its curtailment policies. Under Order No. 636, as before, pipeline sales during supply curtailments, if they occur, will be implemented according to end-use allocation methodologies which include the Title IV priorities. Similarly, as they were under Order No. 436, capacity curtailment plans will generally be developed according to *pro-rata* allocation methodologies with the allowance of end-use measures to provide for emergencies. Furthermore, under the Commission's application

of section 380.5(b)(5) of the Commission's Regulations[275] only new natural gas supply curtailment plans, or any amendment to an existing supply curtailment planthat has a major effect on an entire pipeline system has been subject to an environmental assessment. Thus, any determination regarding the necessity of an EIS for any particular pipeline's supply curtailment tariff compliance filing would at this time be speculative and premature.

Finally, Elizabethtown and Tenneco argue that unbundled pipeline sales should not be subject to the Title IV end-use curtailment priorities, but should be treated as all other gas sellers. Elizabethtown contends that the application of sales curtailment to pipeline sales makes pipeline sellers a less reliable supply source. Tenneco contends that Order No. 636 unduly discriminates against pipeline merchants by requiring only pipelines to follow end-use curtailment plans. In the alternative, Tenneco maintains that end-use sales curtailment should not apply to pipeline marketing affiliates.

The Commission agrees with the arguments advanced by Elizabethtown and the observation of Tenneco that for curtailment purposes unbundled pipeline sales should be treated as all other gas sales. However, as the Commission stated in *Transcontinental Gas Pipe Line Corp.*,[276] "[u]ntil Congress changes the [NGPA], the statutory priority [for pipeline sales] must be observed."[277] Thus, Title IV of the NGPA must continue to apply to pipeline sales only. For the same reason, the

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275. 18 CFR 380.5(b)(5).

276. 57 FERC ¶ 61,365 (1991).

277. *Id.* at 62,117.

Commission agrees with Tenneco that end-use sales curtailment does not apply to pipeline marketing affiliates.

VI. TRANSPORTATION RATES

In Order No. 636, the Commission concluded that the modified fixed variable (MFV) method of cost classification "is not in the public interest, unreasonably hinders competition among gas sellers, and is unjust and unreasonable under NGA Section 5."[278] The Commission adopted SFV in lieu of MFV so that "all gas merchants would be able to compete in a national market without regard to fixed transportation costs included in the usage charge."[279] This competition will "maximize the benefits of wellhead decontrol by increasing the nationwide competition among gas merchants (including pipelines)."[280] Further, "[t]his merchant-to-merchant competition should help to achieve Congress' intent in enacting the Decontrol Act to "over time force the evolution of a set of lowest-cost producers" to "yield lower prices and more abundant supplies" to the benefit of all consumers of gas.[281]

The Commission recognized that the shift to SFV, without any adjustments, could result in cost shifting among customer classes. Hence, the Commission directed that pipelines adopt measures to mitigate cost shifts if the use of SFV will result in a 10 percent or greater increase in revenue responsibility for

278. Order No. 636 at p. 30,434.

279. *Id.*

280. *Id.*

281. *Id.*, *quoting*, H.R. Rep. No. 29, *supra*, at p. 7.

any historic customer class. These mitigation measures are to phase-in any such rate increase over no more than a four year period. The Commission set forth several potential phase-in methods, including the use of a one-part volumetric rate for small customers.

Last, the Commission provided that the determination of rates for interruptible transportation would still be governed by the principles enunciated in the Rate Design Policy Statement.

As discussed below, the Commission is granting rehearing with respect to the designing of rates for small customers. The Commission is retaining SFV for rate design (billing) and cost allocation purposes but will require the use of different ratemaking techniques to distribute revenue responsibility among customers if significant cost shifts occur among pipeline customers, as discussed below, as a result of allocating fixed costs only on the basis of peak entitlements.

A. Rehearing Requests Concerning SFV

A number of petitioners object to the Commission's reasoning in adopting SFV. In brief, they argue that the Commission has rested its decision on invalid goals, has not supported its finding that MFV is not in harmony with those goals if they are valid, and has not supported its finding that SFV is lawful.

As discussed more fully below, the Commission rejects petitioners' contentions. First, as stated above, the Commission is mandating the SFV rate design method for billing (unless the Commission permits otherwise under the exception in 18 CFR 284.8(d)). The Commission believes that its analysis and

conclusions in Order No. 636 comport with its responsibility under the NGA to adopt cost classification methods to achieve goals that are pertinent to current conditions. This requires that the Commission use its judgment to "make the pragmatic adjustments which may be called for by particular circumstances."[282] The Commission must exercise its judgment and discretion in light of the prevalent market, economic, and industry circumstances. Hence, a particular distribution of fixed costs between the reservation and usage charges is not inviolate.[283] And, indeed, as chronicled in Order No. 636, the Commission has changed its goals as market conditions have changed over time.[284] The Commission sees no reason in petitioners' arguments for modifying its conclusions in Order No. 636 to adopt a cost classification method that does not impede the operation of the competitive national wellhead market underlying and envisioned by the Decontrol Act, that MFV does not perform that function but rather hinders achieving that goal, and that simply put, SFV is rationally connected to the Commission's goal of achieving an efficient national gas market which will yield reasonable gas prices to benefit gas consumers and which will send proper market signals to maintain adequate gas supplies.

It is true, as also discussed below, that the adoption of SFV in lieu of MFV may well shift costs among different classes of customers and within classes of customers. However, the Commission concludes that petitioners have not shown any undue harm. First, the Commission is providing for mitigation

282. FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942).

283. Consolidated Gas Supply Corp. v. FPC, 520 F.2d 1176 (D.C. Cir. 1975).

284. Order No. 636 at pp. 30,432-33.

measures to accompany the move to SFV. Second, the Commission has adopted a means for firm customers to shed unwanted firm capacity to those seeking capacity during the restructuring proceedings and thereafter under the capacity reallocation mechanism of section 284.243 of the regulations. Third, the Commission, as discussed below, does not believe that the cost shifts to individual residential gas consumers will be undue in aggregate amount in light of the goals of SFV.

B. Rationale

1. Validity of Goals

The APGA argues that "the Commission's desire to develop a 'competitive, national gas market,' promote competition among gas merchants, and ensure that gas is shipped on even terms are not legitimate rate design goals."[285] It maintains those goals rest outside of the Commission's role because the production end of the natural gas industry is virtually deregulated. The APGA further contends that even if those goals are valid, the Commission may seek to achieve them only subject to its primary responsibility of protecting consumers from the exercise of monopoly power by pipelines. Similarly, Southern California Gas Company (SoCal Gas) maintains that it cannot accept the notion that the Commission has the duty or obligation under the NGA to increase producers' profits at the wellhead, especially after decontrol. Peoples Natural Gas argues that the Commission erred in not applying antitrust law in analyzing the lawfulness of MFV.

The Commission rejects APGA's arguments about the legitimacy of the Commission's goals with respect to rate design.

285. Petition at 80.

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The Commission's interest in the production end of the natural gas industry has not been eliminated by the virtual decontrol of natural gas first sales. True, the Commission has no authority over wellhead gas prices. However, the Commission is still responsible for ensuring that, over the long-term, consumers have access to an adequate supply of natural gas at reasonable prices. It is beyond doubt that the Commission has the authority to regulate pipelines in a manner that fulfills that responsibility. That authority includes the establishing of just and reasonable transportation rates that maximize the benefits of decontrol to gas consumers. The Commission further believes that the rate design goals of Order No. 636 fully comport with the Commission's primary responsibility to protect gas consumers and rejects contentions that it has acted to increase producers' profits. Last, the Commission must apply the antitrust law in analyzing cost classification and rate design methodologies in light of its goals under the NGA. The Commission is not required to analyze rate design, competition, or their relationship under the standards of the antitrust laws.[286]

2. Lawfulness of MFV

Petitioners object to the Commission's conclusion that MFV is unjust and reasonable. The Commission observes that the essence of their objection is to the elimination of MFV as a cost classification method for the purpose of allocating costs among customers rather than to the use of SFV for billing purposes only. If there otherwise would be significant cost shifts, the Commission will require the parties in the restructuring proceedings to develop ratemaking methods that result in a distribution of revenue responsiblity that reflects different

286. *See supra* on the antitrust laws and Transwestern Pipeline Co. v. FERC, 820 F.2d 733 (5th Cir. 1987), *cert. denied*, 484 U.S. 1005 (1988).

customer load profiles so long as SFV is used for billing purposes.[287] For example, seasonal contract quantities (*i.e.*, seasonal entitlements or CDs) may be used to apportion revenue responsiblity among customers. As a general matter, the Commission discourages the creation of customer classes for various transportation services other than the special small customer class provided for in this rule.

The APGA, the Coalition Against Straight Fixed Variable (Coalition), Memphis Light, ConEd, the City of Hamilton!, Ohio (Hamilton), NYSE&G, Northern Illinois Gas, the New England Gas Distributors, the State of Michigan, and Southwest Gas argue that the Commission's conclusion that MFV is unjust and unreasonable because it is not in harmony with the Commission's goals, is unsupported by empirical analysis and is based on faulty assumptions. In particular, they attack, as unsupported, the Commission's conclusion that the shipment of gas on uneven rate terms will inhibit the development of a national gas market by distorting wellhead prices. In particular, the petitioners argue that the following Commission example is unsupported:

> For example, producers in different fields that compete for the market share via different pipelines will often have their competitive positions in that market affected by the amount of fixed costs in the pipelines' respective transportation usage charges and not by the producers' own costs and efficiencies in producing gas.[288]

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287. In other words, the Commission clarifies that using SFV does not foreclose the parties from developing one-part reservation charges based on both annual and peak demand considerations.

288. Order No. 636 at p. 40,434.

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Petitioners maintain that the Commission has not shown that multiple pipelines serve a given market,[289] that, as with other industries, there is no reason why natural gas wellhead markets should not be affected by their location in relation to consuming markets,[290] that shippers expect rates on different pipelines to be different,[291] that gas purchasers make their purchasing decisions on a total delivered cost analysis,[292] that competition has flourished under MFV as shown by the current low wellhead price of gas,[293] and that MFV cannot be anticompetitive because transportation rates will be the same for all shippers, including the pipeline's sales division.[294]

The Commission adheres to its conclusion that MFV is unjust and unreasonable when used widely as a billing method because of its adverse impact on the development of a national and competitive gas market. Under MFV, or any method other than SFV, pipeline usage charges vary depending upon the amount of fixed costs recovered in the usage charge. If customers can choose to take gas from two or more pipelines, they will minimize their transportation costs by baseloading the pipeline with the lowest usage rate and swinging on pipelines with higher

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289. *E.g.*, NYSE&G.

290. *E.g.*, Northern Illinois Gas, Alabama Gas, Peoples Natural Gas similarly argues that shippers expect rates on different pipelines to be different.

291. *E.g.*, Peoples Natural Gas, Southwest Gas.

292. *E.g.*, Cincinnati Gas, the State of Michigan, Hamilton.

293. *E.g.*, CPUC, SoCal Gas.

294. *E.g.*, ConEd, Southwest Gas, Peoples Natural Gas.

usage rates. Pipelines with low usage rates consequently would tend to have higher load factors (enabling them to lower their usage charges even further) as compared to pipelines with more fixed costs in their usage charge. Producers whose gas moves to market over pipelines with low usage charges would be able to have higher sales and/or higher prices than otherwise equally efficient producers whose gas moves over pipelines with higher usage charges. Equally efficient producers whose gas gets to market on pipelines with equal total cost would not be on an equal footing because of the differing rate designs of the pipelines. This is inefficient and creates artificial barriers to the production of gas from one basin as compared to another.

A study done by the Commission staff in 1984, of the number of LDCs connected to mutiple pipelines, showed that, as of 1980, 431 out of 1,443 LDCs surveyed, or 30%, were served by more than one pipeline.[295] On average this subgroup was served by 3.6 pipelines. Since then the trend has been for LDCs to develop more connections to multiple pipelines.

It is important to emphasize that the goal is a national gas market in which efficient, lowest cost producers will flourish and compete.[296] The Commission believes that "[c]ompetition among this set of efficient producers will yield lower prices and more abundant supplies, than will competition among a group of less efficient higher-cost producers."[297] In addition, the

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295. David Mead, "Concentration in the Natural Gas Pipeline Industry," FERC Staff Working Paper (1984).

296. H.R. Rep. No. 29, 101 at Cong., 1st Sess. at p. 7 (1989) (Decontrol Act).

297. *Id.*

Commission believes that fixed costs in pipeline usage charges inhibit the sending of accurate price signals "at the margin" because the inclusion of those costs in the delivered price of day-to-day gas purchases does not allow producers and consumers to see the marginal price of gas that over the long run is more likely to produce the Commission's goal of an efficient national gas market.

This goal is a national goal and not a local goal of producing sets of efficient producers in one production area without regard to efficiency in other production areas throughout the country. Hence, this national concern vitiates the usual approach where the location of supply is relevant to the ability to compete in consuming markets. The Commission is concerned with the impact of multiple pipeline rates on multiple production areas. An efficient national market requires the actual cost of transportation to be reflected in the delivered prices of the gas, and MFV distorts unit delivered prices.

The Commission also believes that its analysis in Order No. 636 is in harmony with opening up the national pipeline grid to all consumers of gas. The essential point is that multiple producing areas and consuming markets have access to each other, even if the producing areas and consuming markets are each served by a single pipeline, but not the same pipeline. In addition, this multiple access should be enhanced by the programs and policies promulgated by Order No. 636. The new flexible delivery point policy, the new capacity reallocation mechanisms, and the recognition of the role of market centers should further open up the pipeline grid to form a national gas market for the meeting of all gas sellers and gas purchasers in the most efficient manner.

The Commission recognizes that gas purchasers use a total

delivered cost analysis to make a decision with respect to entering into new long-term contractual arrangements with pipelines and gas merchants. Some LDCs (such as Brooklyn Union, Cincinnati Gas, and SoCal Gas) are served by more than one pipeline and can purchase gas from different producers with whom they have long-term or spot market arrangements. In making decisions about long-term supply arrangements, it will always be cheaper for LDCs with multiple pipeline connections to baseload the pipeline with the lower usage rate and swing on the pipeline with the higher usage rate. This will affect the long-term contracting decisions of these LDCs both as to the amount of capacity reserved on each pipeline and the long-term gas supply contracts with producers connected to each pipeline. In short, differing usage charges will bias long-term decisionmaking as well as short-term decisionmaking.

The Commission reaffirms its conclusion that MFV rate design is unjust and unreasonable as discussed in Order No. 636. Simply put, MFV rate design hinders, and will continue to hinder, in the unbundled environment created by Order No. 636, and competition by gas sellers in a national gas market based upon their efficiencies, undistorted by varying fixed costs in pipeline usage charges.

APGA and Peoples Natural Gas argue that the Commission erred in stating that continuation of MFV will bias pipeline debt-equity ratios. The Commission's statement that "MFV could bias the debt—equity ratio because pipelines can increase their debt component to lower their usage charges" [298] was an observation of what might happen and was not relied on in finding MFV unjust and unreasonable.

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298. Order No. 636 at p. 30,433.

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3. Lawfulness of SFV

Petitioners raise several arguments in opposition to SFV. First, Southwest Gas, and Peoples Natural Gas argue that there is no evidence of record to support the Commission's conclusion that SFV will result in the shipment of gas under even terms since each pipeline's costs are different, as the Commission recognized in *Iroquois Gas Transmission System.*[299]

It is true that there are many reasons why pipelines may have rate differentials. The purpose in adopting SFV is to minimize the differentials in the usage charge by shifting fixed transmission and storage costs to the reservation charge. The remaining usage charge, (primarily, to cover fuel costs) is small enough that its impact is insignificant on the Commission's goal.

Hamilton maintains that "[u]ntil the market effects of the service restructuring ordered by the Commission are experienced, and the resulting level and efficiency of competition among gas sellers known, the Commission cannot possibly know whether generic application of SFV is necessary, or even useful, in the promotion of competition among gas sellers."[300]

The Commission believes that it has made reasonable predictions about the effect of SFV on the competitiveness of the gas market. The Commission is not required to act only on the basis of hindsight. The Commission may make predictions about the markets it regulates.[301]

299. 53 FERC ¶ 61,194 at p. 61,702 (1990).

300. Petition at 9. Similarly NIEP argues that the Commission should consider the effect of post-restructuring costs on SFV.

301. Environmental Action, Inc. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991).

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Several petitioners[302] argue that the Commission should not mandate SFV because it will increase costs for LDCs serving residential consumers and will decrease costs for high load factor customers, primarily industrials.[303] The Commission believes that the mitigation measures of Order No. 636 and the changes made on rehearing adequately respond to any cost shift (see *infra* on mitigation). In addition, the Commission believes that the ability of consumers to acquire gas at reasonable prices in an efficient, competitive wellhead environment is far more important to the development of a national, long-term gas market. That long-term national gas market will produce benefits to balance any short-term cost shift.[304] Further, the Commission has sound ratemaking techniques available to it, such as the use of seasonal reservation quantities, which would adequately treat undue cost shifts in particular cases. Moreover, the Commission has fashioned a viable capacity release program which should further offset any consequences of a cost shift.

SoCal Gas argues that SFV will reduce competition among producers on competing pipelines because the cost to LDCs of retaining firm capacity will be greater under SFV than under MFV. It argues that MFV's lower demand charges moderate the

302. *E.g.*, Laclede, Gas Company of New Mexico, Public Service Commission of the Commonwealth of Kentucky (Kentucky PSC), CPUC, Pennsylvania PUC, and Maryland Peoples Counsel. The Pennsylvania PUC maintains that the 10 percent mitigation policy shows that SFV is *per se* unreasonable.

303. As stated above, the Commission, contrary to some petitioners (*e.g.*, the CPUC, Socal Gas, Peoples Natural Gas, and the Pennsylvania PUC) believes that SFV will benefit consumers by producing an adequate supply of gas at reasonable prices. Use of SFV is not designed to "help producer net-backs."

304. *See* Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1161 (D.C. Cir 1985).

tension between retention of capacity to serve consumers and maximizing gas-on-gas competition.

SoCal Gas can continue to reserve the same amount of capacity under SFV as it did under MFV and continue to purchase gas from producers behind the pipelines on which it has firm capacity. The Commission fully expects those producers to continue to compete for SoCal Gas' business. Moreover, SoCal Gas can release unneeded capacity, if a replacement shipper can be found or if the pipeline agrees, in the restructuring proceeding as discussed above and under the Commission's capacity releasing program established by Section 284.243 of the Commission's regulations as discussed below.

The NASUCA maintains that SFV will deprive consumers of the ability to freely select among competitive services of supply and transportation by masking price differentials with respect to competing pipelines. The Commission believes that gas purchasers will be able to compute pipeline price differentials in selecting among competitive services because transportation rates will continue to be stated in pipeline tariffs. In addition, comparisons will be easier because only reservation charges need to be compared. The Commission's goal, in any event, is to eliminate as much as possible those differentials in pipeline usage charges.

Several petitioners argue that the Commission has erroneously relied solely on unproven economic theory and not on facts.[305] Similarly, both Peoples Natural Gas and Southwest Gas contend that SFV, as a system of uniform commodity charges, is the functional equivalent of an illegal "basing point" pricing system, and is, therefore, not respectable economic theory.

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305. *E.g.*, Hamilton and City Gas.

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The Commission believes that it has relied on sound economics. The development of a competitive national gas market consisting of lowest-cost, efficient producers will in the long run redound to the benefit to consumers and that the inclusion of fixed costs in pipeline firm service usage charges will inhibit that goal by distorting producer to producer competition on a nationwide basis.

The Commission does not agree that SFV may not be adopted because it resembles an illegal "basing point" pricing system where the delivered prices of a product (such as cement) are identical at any given point in order to eliminate price competition. First, the Commission is authorized to establish pipeline transportation rates to achieve the goals it determines are in the public interest. Second, SFV does not mandate a uniform delivered gas price, which is the gas price plus the transportation rate nor does it establish uniform transportation (reservation) charges. The Commission believes that the competitive national gas market will result in vigorous gas on gas competition.

C. Allocation of Costs Among Customers

Alabama Gas argues that the Commission's nationwide gas market rationale does not provide a basis for changing cost classification for allocation purposes. It refers to the Commission's recent opinion in *Panhandle Eastern Pipe Line Corp.*, where the Commission used MFV for allocation and SFV for design.[306]

The Gas Company of New Mexico asks the Commission to clarify that it has not mandated a particular basis for allocating

306. 57 FERC ¶ 61,264 (1991), *order on reh'g*, 59 FERC ¶ 61,244 (1992).

costs among customer classes or calculating the demand charge (*e.g.*, peak requirements-annual requirements or two-part demand charge).

Southwest Gas submits that on rehearing the Commission should clarify that it did not intend to prejudice the issues of the appropriateness of the use of a one part demand charge or mandate the use of peak determinants to allocate costs.

CIG asks the Commission to clarify whether demand costs are to be allocated only to peak usage or entitlement and designed into a single part reservation charge or whether it and the parties can base demand-cost allocation and the design of reservation charges on some weighing of annual entitlements to service.

The Commission's primary aim is to institute SFV on a generic basis for rate design (*i.e.*, billing purposes) in order to minimize the costs recovered in the usage charge because of the effect on purchasing decisions. Although the Commission agrees that to achieve this purpose it is not necessary for a pipeline also to use the SFV method for the allocation of costs among its customers,[307] traditionally, the Commission has used

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307. In Order No. 636 the Commission explained the five traditional steps in the ratemaking process. Order No. 636 at p. 30,431. In Order No. 636, the Commission addressed the issue of cost classification for cost allocation purposes and billing (rate design) purposes and concluded that SFV is the just and reasonable cost classification method for the assignment of costs to a reservation charge. The Commission did not directly address the fourth task of apportioning (allocating) classified costs among classes of customers or zones. This task allocates the costs, assigned under SFV to the reservation charge, by using various techniques to determine the amount of costs to be assigned to a particular zone or customer class (*e.g.*, contract demand quantities or three day peak volumes).

the same method for rate design and for the allocation of costs among customers. But, it does not have to be so.

However, the Commission clarifies that it will require the parties to use different ratemaking techniques in connection with the distribution of revenue responsibility among customers to avoid significant cost shifting that may result from the elimination of the two-part demand charge or the allocation of costs based on peak day demand. The pipeline would first use SFV to classify (*i.e.*, assign) all of its fixed transmission and appropriate storage costs to a one-part reservation charge for both allocation and billing purposes. If that classification causes significant cost shifts, the pipeline is required to use some measure, such as seasonal contract quantities (*i.e.*, seasonal entitlements or CDs) as a means to counteract those shifts. This would enable firm customers to lower their daily reservation quantities for the off peak season and keep the higher quantity needed for the peak season.[308] Thus, if significant cost shifts

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308. For example, assume a pipeline with an annual reservation charge revenue requirement of $10 million and two customers A and B, each with a daily reservation quantity of 166,666 Mcf per day. Thus the annual reservation quantity (billing determinants) is 4 million Mcf (2 times 12 times 166,666). The reservation charge would be $2.50 per Mcf and each would pay $5 million. However, if seasonal contract quantities were used the revenue responsibility of each would change as follows. Assume that Customer A elects an off-peak daily reservation quantity of 133,333 for a reservation quantity (billing determinants) of 800,000 Mcf (for a six month period) and an annual total of 1.8 million Mcf. Customer B elects an off-peak daily reservation quantity of 33,333 Mcf for a reservation quantity (billing determinants) of 200,000 Mcf. The result is an annual total of 1.2 million Mcf for Customer B. Thus, the combined reservation quantities (billing determinants) for the two customers would be 3.0 million Mcf and the reservation charge would be $3.33 per Mcf ($10 million divided by 3 million Mcf). Customer A would pay a total of $6 million ($3.33 times 1.8 million Mcf) and Customer B would pay $4 million ($3.33 times 1.2 million Mcf). Under either case, the pipeline will recover its

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still would occur among customers, due to the allocation of costs on peak day demand, the pipeline is required to use other appropriate techniques, such as seasonal CDs, to allocate costs. However, SFV must still be used for billing so that all fixed costs are recovered in the reservation charge.

Pipelines are required to use, in their compliance filings, SFV to allocate costs between services and zones. The Commission directs the parties in the individual proceedings to develop methods for allocating costs among services and distributing revenue responsibility among customers that will minimize significant cost shifting. The Commission strongly encourages the use of seasonal contract quantities to replicate, in part, the allocation of costs based on peak and annual considerations. The parties can explore other methods, however, a two-part reservation charge is not appropriate for allocation or billing purposes. The D-2 charge was based on usage patterns and is therefore not in harmony with the goal of SFV to minimize charges based on actual usage because usage charges can affect gas purchasing decisions. In addition, as a general matter, the Commission discourages the creation of customer classes, other than the special small customer class provided for in this rule, or if necessary during the four year mitigation period. Rather, the Commission intends for the pipelines and the paties to develop similar rates for similar services, consistent with the requirement set forth in Section 284.8(b) of the Commission's regulations.[309]

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revenue requirement. Use of seasonal CDs only changes the way that the revenue requirement is allocated between the two customers.

309. Section 284.8(b) provides that an interstate or intrastate pipeline that provides firm service under Part 284 must "provide such service without any undue discrimination or preference in the quality of service, the duration

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If at the end of this ratemaking process significant cost shifts still result, the Commission will require a four-year mitigation plan, as discussed below, to phase-in the transition. In all events, the Commission will require the use of SFV for the rate design (billing) unless ordered otherwise in accordance with 18 CFR 284.8(b).

D. Rates for Small Customers

Order No. 636 stated that "the small customers can continue to receive firm transportation under a one-part volumetric rate computed at an imputed load factor similar to the manner in which their current sales rates are determined."[310] The Commission later indicated that the use of a one-part volumetric rate was a potential mitigation method for phasing-in SFV.

City Gas seeks clarification that "pipelines will be required to compute small customer rates on a one-part volumetric basis at the imputed load factor underlying the pipeline's currently effective small customer sales rate."[311] Similarly, the APGA seeks clarification that one-part, volumetric rates are not merely a temporary rate design mitigation mechanism. Atlanta Gas, however, opposes the small customer imputed load factor as an unwarranted subsidization by large customers and inconsistent with the Commission's "distorting factor" analysis.

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of service, the categories, prices or volumes of natural gas to be transported, *customer classification*, or undue discrimination or preference of any kind." (emphasis added).

310. Order No. 636 at p. 30,411 (footnote omitted).

311. Petition at 9.

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The Commission here is clarifying this small customer rate issue to preserve the status quo for this particular class of customers. In the Commission's view, this will not have an unreasonable impact on the Commission's goals in adopting SFV. The Commission is requiring all pipelines that, on May 18, 1992, offered a small customer sales or firm transportation service on a one-part volumetric basis at an imputed load factor rate to continue to offer firm and no-notice transportation services on the same basis. In addition, the Commission is requiring those pipelines to consider enlarging the size of the small customer class on their systems to include any customer with the right to transport up to 10,000 Mcf or Dth/day on a firm basis. Whether the small customer class should be enlarged up to 10,000 Mcf or Dth/day on specific pipelines will be resolved by the Commission in the specific restructuring proceedings. The purpose for enlarging the small customer class would be to mitigate the effect, of shifting to the SFV method, on small customers who do not currently qualify for a pipeline's small customer rate schedule. However, the Commission is also requiring eligible small customers that elect to retain or receive small customer service not to ship gas under any interruptible transportation service available from the pipeline or not to ship gas as a replacement shipper under the capacity releasing mechanism of Section 284.243 unless the customer has exhausted its daily levels of firm service entitlement for that day. Other eligibility criteria would be based on the pipeline's existing tariff. The Commission is imposing this narrow limitation because the small customers are required to pay only when they use the pipeline. This serves the same functional purpose as sole supplier provisions did in the same customers' contracts to the extent they had those provisions.

In their compliance filings, the pipelines must file rates for the small customer service determined by using a load factor

no less than the current imputed load factor. If the pipeline or another party, such as Atlanta Gas, wants to lower the existing imputed load factor or eliminate the use of a one-part rate, it must seek to do so in a new rate proceeding and not in the restructuring proceeding.

E. Costs Shifts to Firm Customers

The Coalition argues that SFV will cause a massive industry-wide shifting of costs from interruptible transportation customers to firm customers. The Coalition claims that a change from Seaboard to SFV will shift $5.9 billion to the demand charge and a change from MFV to SFV will shift $4.3 billion to the demand charge. The Coalition further maintains that approximately 60 percent of total throughput is interruptible industrial transportation, although they do not cite a source for this number.[312] It asserts that this results in shifts of about $3 billion (60% x $5 billion) per year or $60 per year per customer.[313]

The Coalition's study does not present an accurate portrait of the changes effected by Order No. 636. The Commission expects the overall effect of Order No. 636 will benefit generally industry participants by furthering the creation of an efficient national wellhead market. Hence, focusing on cost shifts is to focus on but one aspect of Order No. 636. Moreover, cost shifting

312. The Coalition's information may have come from the Energy Information Administration's (EIA) Natural Gas Monthly publication which shows gas consumption by Electric Utilities and Industrial Customers in 1990 of about 58 percent. Energy Information Administration/Natural Gas Monthly (May 1992); DOE/EIA - 0310 (92/05), from: Table 3. Natural Gas Consumption in the United States, 1986-1992.

313. The Coalition has assumed 50 million gas customers.

is not a generic matter; the key question is how costs are redistributed among customers on a particular pipeline. In addition, the Commission has provided measures to deal with cost shifts (see *infra* on cost allocation and rate design).

Despite its neglect of the benefits from Order No. 636, the Coalition attempts to quantify the possible shift in costs from interruptible customers to firm customers brought about by the shift to SFV rate design. However, the Coalition is mistaken both as to how costs are recovered from interruptible shippers now and how they will be recovered under SFV rates. Moreover, all the numbers the Coalition uses to support its estimate are inappropriate. The Coalition appears to believe that interruptible shippers pay only a portion of the fixed costs that are assigned to the commodity charge, whereas in fact 100 percent load factor interruptible transportation rates are designed to recover some fixed costs in the demand charge. Under SFV, the Coalition appears to believe that interruptible transportation shippers will not pay any portion of the pipeline's fixed costs, whereas in fact neither this order nor Order No. 636 necessarily requires any change to the methods used for setting interruptible rates.

Using certain assumptions the Commission can generally estimate the amount of costs that could shift. Under MFV, costs are split into three categories. First, the pipeline's return on equity and associated taxes go into the usage category. In 1990, these amounted to $1.7 billion,[314] rather than the $4.3 billion

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314. Energy Information Administration/Statistics of Natural Gas Pipeline Companies 1990; DOE/EIA - 0145(90), from: Table 3. Composite Statement of Income and Retained Earnings, Major Pipeline Companies, 1981-1990. Table 3 shows gas operating revenues of $1.685 billion. From this we deduct interest expense of $.594 billion (assuming the company wide ratio of 35.23 per cent of interest expense to net income holds for the transmission

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estimated by the Coalition.[315] These costs are recovered from each unit of throughput. In 1990, total throughput for the interstate pipeline system was about 19.9 Tcf.[316] Total throughput was almost evenly divided between firm customers (9.9 Tcf) and interruptible shippers (10 Tcf).[317] Thus, interruptible shippers paid about 50 percent of fixed usage costs ($.85 billion). The remaining fixed costs of the pipeline, about $7.8 billion,[318]

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function alone) to get a return (after taxes) on equity of $1.09 billion. The federal and state composite tax rate is about 36 per cent, so a pre-tax income of $1.70 billion is necessary to yield an after tax income of $1.09 billion.

315. The Coalition's figure is overstated because the net income reported in Statistics of Natural Gas Pipeline Companies, EIA- 0145(90), Table 3, includes income relating to the pipelines total business, utility and non-utility, and not just to transmission expenses as it should. The tax figure is overstated for similar reasons and does not reflect the income tax allowance as included in rates.

316. Interstate Natural Gas Association of America, Issue Analysis: Carriage Through 1990 (July 1991), from: Table A-1, which shows carriage for market plus sales of 17.109 Quads. The pipelines in INGAA's survey account for 86 per cent of gas deliveries; the figure in the text was derived by multiplying 17 x 1/.86 and rounding.

317. *Id.* Table A-7, Sales and Firm and Interruptible Transportation as a Percentage of Total Delivered for Market, shows 51 percent as the share of interruptible transportation.

318. This was estimated by subtracting total purchased gas costs of $12 billion, Statistics of Natural Gas Pipeline Companies 1990, Table 9, from the revenue from sales of $16 billion *Id.*, recovered from sales customers. Add to this, revenues from transporting gas of others of $5.5 billion, to get the $9.5 billion in the text. The Commission recognizes that there are upstream capacity costs representing inter pipeline sales (Account No. 858 costs) included in the $12 billion.

were split fifty-fifty between D1 costs ($3.9 billion), which are recovered on the basis of contract demand (CD) with an imputed CD for interruptible customers, and D2 costs ($3.9 billion), which are recovered on the basis of nominated annual throughput for firm customers and projected annual throughput for interruptible shippers. Total contract demand for all interstate customers in 1990 was about 75 Bcf per day or 27.5 Tcf per year.[319] If projected interruptible transportation throughput was assumed equal to the actual of 10 Tcf, then the $3.9 billion per year of D1 costs would have been recovered from each of the 37.5 Tcf reserved per year (27.5 in CD plus 10 Tcf in interruptible transportation imputed CD).[320] Interruptible transportation shippers thus paid 27 percent (10/37.5) of the D1 costs or about $1 billion. Similarly, if one assumes that firm annual D2 nominations are equal to actual firm annual throughput, then the D2 costs of $3.9 billion were recovered from each of 20 Tcf units shipped, and interruptible transportation shippers paid about 50 percent of $1.95 billion.

Thus, the Commission estimates that under MFV, interruptible transportation shippers paid about 40 per cent of the total fixed costs, or about $3.8 billion. Shifting to SFV would have put all costs in the D1 category. If there were no change in the interruptible transportation projected throughput, interruptible transportation customers would have been allocated 27 percent of the total, or about $2.5 billion. There would have been a shift of costs from interruptible transportation shippers to firm customers of about $1.3 billion, rather than $3 billion estimated by the Coalition.

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319. Capacity and Service on the Interstate Natural Gas Pipeline System 1990, EIA-0556, June 1992, Table ES1, p. xi.

320. This results in a D1 charge of 10.4 cents per mcf reserved per day, or $3.12 per month.

But even this number is too large. Many firm sales customers have been buying gas from non-pipeline sellers and shipping it on an interruptible basis. In 1990, at least 27 percent of the 10 Tcf of interruptible transportation throughput was for LDCs.[321] Thus, non-LDC interruptible transportation shippers paid about $2.8 billion in 1990, not $3.8 billion.[322] If the D1 billing determinants are adjusted to take into account a decrease in interruptible transportation done by LDCs, interruptible transportation would be projected to be 7.3 Tcf, rather than 10 Tcf. Non-LDC interruptible transportation shippers would pay about 21 percent (7.3/(7.3 + 27.5)) of the costs, or about $2 billion. This means the shift from non-LDC interruptible transportation customers to firm customers is about $.8 billion ($2.8 - $2).[323]

If $.8 billion[324] was shifted to firm customers from

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321. INGAA's Carriage Through 1990, Table B-3, *supra*, shows that LDCs accounted for 27 percent [17/64] of the total IT throughput, while marketers accounted for 61 percent [39/64]. It is likely that marketers resold some of this gas to LDCs, so the 27 percent figure is probably an underestimate.

322. This is derived by multiplying 73 percent (non-LDC interruptible shippers throughput) times $3.8 billion, $2.8 billion.

323. This is derived by multiplying 21 percent (non LDC interruptible transportation share of D1 costs times $9.5 billion, $2 billion, and subtracting $2 billion from $2.8 billion.

324. Even this number is too large, because D2 costs are far less than the amount assumed since many pipelines have already eliminated them. In addition, some major pipelines are already operating on EFV which puts only half the MFV amount in commodity and none in D2. Moreover, some pipelines already have SFV in effect and the calculation does not take into account any revenue from firm capacity holders releasing capacity.

interruptible shippers, how much more would the 50 million residential gas customers pay? Residentials consumed 26 percent of the total gas delivered to consumers in 1990.[325] If they paid a proportionate share of the shift, their annual bill would increase by $.21 billion, or about $4.20 per year or 35 cents per month. If they paid *all* of the shift (that is, commercial, industrial and electric utility customers of LDCs paid *none* of the shift), then their annual bill would increase by $16.20 or by $1.35 per month. Since LDCs billed residential gas customers over $25 billion in 1990,[326] or over $500 per customer per year, even this most extreme shift would amount to about a three percent increase in annual bills. While the Commission believes its estimate is reasonable and more accurate than the Coalition's, the Commission recognizes that it is not a precise estimate of potential cost shifts.

F. Mitigation of Cost Shifts

In Order No. 636, the Commission recognized that the change from the use of MFV can result in the shifting of revenue responsibility among classes of customers. The Commission concluded that it was appropriate to require pipelines to mitigate a shift in revenue responsibility if it results in a 10 percent or greater increase in revenue responsibility for any historic customer class. The Commission is requiring each pipeline to develop and implement a plan to phase-in any such rate increase over no more than four years.

Several petitioners make a variety of arguments about why the mitigation measures are not adequate. They argue that the

325. Natural Gas Monthly, *supra*, Table 3.

326. Gas Facts, 1990 Data, American Gas Association, Table 7-1.

Commission has provided no rationale to support the ten percent or greater bright line test, that mitigation should be by customer rather than by customer class, and that permanent measures are necessary to avoid unjust and unreasonable rates.[327] Some petitioners argue that mitigation should be a restructuring issue without a threshold or phase-in period.[328]

The Industrial Groups maintain that the combination of SFV with mitigation through cost allocation methods will result in different rates for the same service which is discriminatory and, if based on historical usage patterns, unlawful retroactive ratemaking. It adds that there is little basis to assume that historical load factors will remain the same in light of the institution of capacity releasing, flexible delivery points, and open access storage.[329] They suggest phasing-in SFV at the cost classification stage based on current load factors so that all customers are treated equally.

Northern Illinois Gas supports mitigation but not simply to shift costs to other firm customers, "who are already paying all fixed costs properly related to their capacity entitlements."[330]

Several petitioners ask for clarifications. Northwest Pipeline

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327. *E.g.*, Hamilton, Gas Company of New Mexico, Kentucky PSC, Citizen Action, Kansas Corporation Commission (KCC), NASUCA, Tennessee and Columbia Small Customers, Alabama Gas, and Cascade.

328. *E.g.*, Hamilton, Alabama Gas.

329. The Industrial Groups also note that mitigative rates will result in different capacity releasing prices.

330. Petition at 23.

asks the Commission to clarify "how the historical customer class will be defined — by pipeline historic rate schedules, by current pipeline rate schedules, by total yearly throughput, by load factor profile, by individual customer or other criteria."[331]

The KCC is concerned about strict application of use of a pipeline's last approved cost classification and rate design method in performing the mitigation analysis. It cites, for example, Williams Natural Gas Company's one-part commodity firm sales rate.

City Gas asks for clarification about what costs and in what manner the Commission will compare them to determine whether a customer class that no longer exists after Order No. 636 has received increased revenue responsibility. It asks whether the Commission will compare SFV rates with MFV rates based on the currently effective cost of service and service portfolio, or based on projected, post-Order No. 636 cost of service and service portfolio.

The Commission upholds the mitigation approach set forth in Order No. 636. The Commission believes a fixed mitigation trigger for the industry is appropriate rather than a case-by-case approach, because SFV is being adopted on a generic basis. Based on the Commission's judgment, 10 percent is appropriate for the bright-line test. However, with the changes made in this order, the Commission expects there to be a diminished need to phase-in the changes required by the rule. Small customers are retaining their right to a one-part volumetric rate at an imputed load factor and pipelines will use an apportionment method , such as seasonal reservation quantities, to appropriately allocate costs among individual customers. These changes should minimize the need to use the phase-in mitigation measures.

331. Petition at 10,11.

If needed, however, the Commission continues to believe that the need for mandatory mitigation should be determined by a measure of shifts between historic customer class rather than by individual customer, because rates historically have been set by customer class and not for individual customers.

The Commission believes further that the four-year mitigation plan should be transitional rather than permanent because SFV is a just and reasonable cost classification method. Mitigation is adopted as an equitable matter solely to allow the orderly transition to SFV.

While it is true that four-year mitigation, if needed, may result in varying rates for the same service depending upon the mitigation measure adopted, this discrimination is not undue for this transition period because mitigation is appropriate to soften the impact of the adoption of SFV. Mitigation is not retroactive ratemaking. The pipelines will not be recovering past losses in present rates. Rather, the mitigation formula is similar to any phasing-in or phasing-out of a subsidy.

It is possible, as maintained by the Industrial Groups, that a customer's load factor will change in light of the policies instituted by Order No. 636. But the Commission is mitigating by historic classes of customers to alleviate rate shock among those different classes of customers. Individual changes in load factor are not pertinent to mitigation by classes of customers.

The Commission clarifies that historic customer class refers to classes existing prior to May 18, 1992. For example, if a pipeline has a firm sales customer class existing prior to May 18, 1992, and that class will have an 11 percent increase, the pipeline must mitigate the impact of the change to SFV for all

members of that class. A pipeline must use its throughput and cost-of-service underlying the currently effective rates (even if they are subject to refund) to make this mitigation calculation.

G. Other Rate Designs

In Order No. 636, the Commission stated that it will consider alternative rate design proposals when the parties agree to a rate design other than SFV, but stated that those parties supporting a rate design other than SFV bore a heavy burden of persuasion.

New Jersey Natural, Pennsylvania PUC, and National Association of Regulatory Utility Commission (NARUC) object to the "heavy burden" standard. For example, NAURC argues that it is concerned it will become an irrebuttable presumption in favor of SFV. It asks the Commission to provide greater detail about what needs to be shown to meet the heavy burden of persuasion. In addition, the Wisconsin Distributor Group and NARUC maintain that the Commission should clarify that it will accept rather than consider other rate designs. The former contends that the Commission should grant effect to substantially uncontested agreements among interested parties. The Iowa, Missouri, and Wisconsin Commission suggest the following approach:

> If all of the rate case participants wish to implement something other than pure SFV, the Commission should accept the choice. If a substantial majority of rate case participants agree on a rate design which does not implement pure SFV, the Commission should place the burden on the objecting parties to

justify why the majority agreement should not be accepted by the Commission.[332]

Columbia Gas Distribution Companies maintain that the Commission has precluded itself from adopting MFV, in giving effect to the parties' agreement to MFV, by its finding that MFV, is unjust and unreasonable, a possible "per se" NGA Section 5 violation. They suggest amending Order No. 636 to clarify, "in terms stronger than 'unless the Commission permits otherwise' . . . that the Commission retains the ability to approve non-SFV rate designs, including MFV."[333]

The Commission denies rehearing and adheres to its Order No. 636 discussion that it will carefully consider arguments for and against deviations from SFV, with the advocates against SFV bearing the burden of persuasion. This is not an irrebuttable presumption. At a minimum, opponents of SFV must demonstrate that SFV is not needed to effectuate the goals of Order No. 636. The Commission's finding that MFV is unjust and unreasonable is not a "per se" finding with respect to future individual pipeline rate proceedings, but a generic finding that the impact of MFV for billing purposes is unjust and unreasonable on a generic basis under the present circumstances.[334]

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332. Petition at 16-17.

333. Petition at 5.

334. See Freeport Interstate Pipeline Co., 59 FERC ¶ 61,378 (1992) for an example of the retention of MFV based on individual circumstances.

Appendix C

H. Other Matters

1. Alternative Fuels

Southwest Gas argues that there is no record support for the Commission's conclusion that SFV is needed to make gas more competitive *vis-a-vis* other fuels and to encourage the use of gas (as opposed to foreign oil). It maintains that the delivered price of natural gas is already well below that of heavy oil and well above that of coal.[335] Alabama Gas adds that the Commission has ignored the pipelines' ability to discount rates.

The Commission's conclusion was not that SFV is needed now to make gas more competitive with other fuels, but that SFV will enable gas to compete more readily, on a timely basis, by allowing the price of gas to adjust without regard to transportation fixed costs.

2. Impact on Gas Prices

NYSE&G maintains that the Commission needs to perform an elasticity analysis of the impact of changes in prices for pipeline transportation service on the demand for supplies behind competing pipelines. The Commission is not required to perform impact studies in connection with SFV's impact on the demand and price of gas suppliers.[336] The Commission believes that the effect of SFV on national wellhead competition will be to produce an adequate supply of gas at reasonable prices.

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335. See also Northern Illinois Gas, Atlanta Gas, Peoples Natural Gas, and Alabama Gas.

336. Cf. Wisconsin Gas Co., v. FERC, 770 F.2d 1144, 1155 (D.C. Cir. 1985).

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3. Other Rate Design Goals

Several petitioners argue that the Commission in adopting SFV has ignored past precedents and goals with respect to the designing of rates.

Washington Gas contends that there is no evidence to support the finding that the MFV rate design fails to promote the efficiency goals under Commission regulations or the Rate Design Policy Statement, or that a mandated SFV will improve economic efficiency. It maintains that there is no evidence that the higher demand charge of SFV would better ration firm capacity generally or a connection between MFV and under utilized capacity.

Arizona Electric argues that SFV encourages usage at peak when rationing is needed and, therefore, does not promote efficient utilization, and ignores the market-clearing role of usage charges.

Washington Gas also argues that the Commission should reverse its mandate of SFV and allow particular rate designs to be developed in individual pipeline rate proceedings under the guidance of the Rate Design Policy Statement.

The Commission did not apply the policies enunciated in the Rate Design Policy Statement because in its current assessment of the prevalent economic and market circumstances it believes the goal of achieving an efficient, national gas market is the factor that should control the selection of the appropriate rate design method. This does not mean that rationing capacity and maximizing throughput are not legitimate rate design functions. For example, it may be appropriate to apply the Rate

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Design Policy Statement in determining whether seasonal rates are appropriate.

The Coalition, Southern Indiana, and the State of Michigan maintain that the Commission ignored precedent by failing to take into account the fact that a pipeline incurs fixed costs to serve all throughput.[337] The Coalition maintains that several costs are the responsibility of total throughput under the "cost responsibility" principle.[338]

The Commission recognizes that a pipeline has throughput throughout the year. The proper allocation of fixed costs between peak and off peak customers presents a difficult issue which regulators have grappled with for many years. This, like all other ratemaking matters, is not an exact science and the Commission must use its judgement and expertise to select ratemaking practices that benefit all gas consumers.

As a result, the Commission believes that the goals to be accomplished via SFV outweigh generally the goal of allocating fixed costs to annual throughput. There are many functions that can be performed by rate design. The allocation of fixed costs to annual throughput is but one of them. The Commission is not bound to adopt a cost classification that performs that function when another function is more appropriate in the prevalent circumstances. However, as discussed above, the Commission is requiring adjustments in connection with the distribution for revenue responsiblity among customers to avoid significant cost shifts among pipeline customers.

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337. *See, e.g.*, Atlantic Seaboard Corp., 11 FPC 43 (1952) and Texas Eastern Transmission Corp., 30 FERC ¶ 61,144 (1985).

338. *See, e.g.*, Atlantic Seaboard Corp., 11 FPC 43 (1952) and Texas Eastern Transmission Corp., 30 FERC ¶ 61,144 (1985).

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Several petitioners argue that under SFV pipelines will have no incentive to operate their systems on an efficient basis to control costs and to maximize throughput.[339] Brooklyn Union argues that the "Commission must require pipelines to implement appropriate incentive rate mechanisms at the same time that SFV rates are implemented."[340] Brooklyn Union argues that this is necessary to replace the loss of the tool against excessive pipeline charges of not fully recovering fixed costs unless pipelines minimize costs and operate efficiently. However, other petitioners argue that the Commission should defer the adoption of SFV and consider SFV and incentive ratemaking together in a separate proceeding.[341] United Distribution Companies maintains that incentive ratemaking should not be part of the restructuring process to eliminate a pipeline bargaining chip. It asks the Commission to reject incentive rate filings that do not give the pipeline a stake in throughput. The Commission will address incentive ratemaking matters below. Here, it suffices to state that the Commission will not require incentive ratemaking to be implemented at the same time as SFV in the compliance filings to Order No. 636.

4. Alternative Solutions

Arizona Electric Cooperative argues that "geographic equalization" (*i.e.* producers in different areas) could be achieved

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339. *e.g.*, Northern Illinois Gas, the Industrial Groups, SoCal Gas, Southern Indiana Gas and Electric, the Gas Company of New Mexico, Laclede Gas, Kentucky PSC, the Illinois Commerce Commission, Citizen Action, CPUC, NASUCA, Citizens Gas, and APGA.

340. Petition at 15.

341. ConEd, NYSE&G, Peoples Natural Gas, Alabama Gas, New England Gas Distributors, NIEP, and AGD.

by discounting or by volumetric transportation rates based on marginal costs. Its maintains that those rates will create demand-responsive volumetric charges which will rise during peak usage periods. It adds that reservation fees would then be set at a much lower level because they would only have to recover any revenue shortfall expected to result from the volumetric charges.

Peoples Natural Gas asserts that the Commission should adopt SFV rates as utilized in the electric industry, where the demand charges apply to customer's actual peak consumption during the given months.

Peoples Natural Gas argues that the Commission could have remedied the distortion by adopting a uniform volumetric rate (including fixed costs) on all pipelines without harming consumers by shifting all costs to them from producers as it claims is done by SFV.

The Industrial Groups agree that MFV is unlawful, but would prefer Enhanced Fixed Variable, which includes 50 percent of a pipeline's equity return and related taxes in its usage charge.

The Commission believes that SFV, as adopted by in Order No. 636, is the best rate design vehicle for achieving the Commission's goals. This is because SFV, unlike the other proposals, best eliminates the distorting impact of pipeline fixed costs on wellhead competition. The other proposals, by recovering fixed costs through usage factors, would not do that.

5. Unallocated Capacity

Several petitioners argue that the pipelines should bear

the costs associated with unbooked firm capacity.[342]

Order No. 636 did not address the issue of the appropriate aggregate firm volumes to use in designing the firm transportation reservation charges. This is, therefore, not an Order No. 636 restructuring issue but rather, is an issue for a rate proceeding.

6. New Entrants

SoCal Gas argues that SFV will, like minimum bills, make it substantially more difficult for new pipelines to compete with existing pipelines to provide firm transportation services in existing markets. The Commission believes that new capacity should be built to meet demand for capacity. If demand exists, SFV should not be a deterrent to new construction.

7. Demand Charge Credits

ConEd, AGD, and Peoples Natural Gas argue that pipelines should be required to provide demand charge credits during service interruption or curtailment to provide an incentive to expeditiously restore service.[343] Because this issue does not pertain to Order No. 636, it should be resolved in individual rate proceedings and not in this order or the restructuring proceedings.

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342. Northern Illinois Gas, Illinois Power, Northern Indiana, and City Gas (suggests assigning these costs to commodity charge). United Distribution Companies suggests designing at 110% throughput to introduce the element of competitive risk.

343. *See* Northern Natural Gas Co., 57 FERC ¶ 61,105 at p. 61,400 (1991).

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8. Rate of Return/Risk

In Order No. 636, the Commission stated that "pipeline risk is a matter for pipeline-specific analysis in light of all risks."[344]

Several petitioners asks the Commission to reduce the pipelines' rate of return on equity and to reflect the decline in pipeline risk under SFV.[345] The Arizona Direct Customers asks the Commission to clarify "that all other things being equal, a pipeline's move from the MFV to SFV method of cost classification and rate design reduces a pipeline's risk of inadequate revenue recovery, and this reduction in risk is a relevant factor in arriving at an appropriate return on equity."[346] The New England Distributors maintain that the Commission should act in individual NGA section 4 proceedings in order to consider reduced pipeline risks.

The pipelines argue that their risk will increase after restructuring. For example, INGAA submits that "if the Commission considers all risk confronting pipelines after restructuring, it will allow pipelines higher rates of return on equity."[347] INGAA refers to risk related to the "difference between the rate negotiated and the maximum rate" and risk associated with interruptible service because the pipeline may not sell its own capacity first. ANR asks the Commission to clarify that the implementation of the SFV rate design does not

344. Order No. 636 at p. 30,437.

345. Pennsylvania PUC, Citizen Action, CPUC, the Industrial Groups.

346. Petition 10.

347. Petition 7. See also Natural's Petition at 19.

itself require a lowering of the return on equity component of a pipeline's rates.

The Commission adheres to Order No. 636's conclusion that "pipeline risk is a matter for pipeline-specific analysis in light of all risks."[348] As such, this is not a restructuring issue but rather is an issue that may be raised in individual pipeline rate proceedings where the Commission examines a pipeline's cost-of-service, including the return on equity.

9. Prospective Basis

The APGA asks for clarification that pipelines may implement SFV increases on a prospective basis only and not retroactively to the effective date of any currently active section 4 proceeding. The Commission so clarifies, unless the pipeline proposed SFV in such a proceeding, then a mitigation measure may be required back to the date the rates became effective in connection with the implementation of SFV.

10. By-Pass

The State of Michigan argues that SFV will create incentives for by-pass. The Commission will discuss by-pass issues below in Part IX, B, 13. Here, it suffices to state that SFV's impact on by-pass is a speculative matter dependent on the method for the flow though of fixed costs used by a state commission.

11. Section 7(c) Transportation

National Fuel asks the Commission to require pipelines to adopt SFV for individual NGA section 7(c) transportation

348. Order No. 636 at p. 30,437.

services because the Commission's rationale applies with equal force to those services. The Commission agrees that the rationale for SFV applies to all firm transportation. As the Commission has required in the past, the same rates must be charged for individually authorized NGA section 7(c) transportation and for Part 284 transportation and will permit individual NGA section 7(c) transportation rates to be so designed. If a party opposes that design for those services, it may raise its objection in the pertinent restructuring proceeding.

12. Vintage Pricing

Great Lakes Gas Transmission Limited Partnership (Great Lakes) requests clarification that equal transportation on even terms requires the elimination of vintage pricing in favor of a uniform, market-based rate for comparable transportation services (constrained by the pipeline's highest cost-based tariff rate applicable to such services). The Commission will address this issue in Great Lakes' own proceedings concerned with vintage pricing rather than here or in the restructuring proceeding.

13. Rate Design Policy Statement Policies

In Order No. 636, the Commission stated that the policies enunciated in the Rate Design Policy Statement continue in effect except for the classification of costs to the reservation and usage charges. The Commission specifically referred to, as examples, the determination of rates for interruptible transportation, the discounting of rates, and mileage-based rates.

The Arizona Direct Customers seeks clarification that "pipelines must unbundle gathering costs from the mainline rates

and that all other principles set forth in the Policy Statement and not explicitly modified by the Final Rule Remain in effect."[349] The Commission reiterates that the policies enunciated in the Rate Design Policy Statement continue in effect except for the classification of costs to the reservation and usage charges for billing purposes For example, as discussed above, pipelines can allocate or apportion costs under other ratemaking techniques, such as seasonal contract entitlements. In contrast, under seasonal rates, peak period reservation charges would be higher than off-peak reservation charges. Cost unbundling is discussed below.

14. Unbundling of Costs

NGSA seeks clarification with respect to Order No. 636's alleged vagueness concerning cost unbundling. NGSA asks the Commission to endorse cost unbundling by expressly amending Sections 284.7(d)(i) and (ii) to insert "unbundled" before service, and by including Section 284.7 among the listed regulations subject to implementation in the order No. 636 compliance filing.[350] NGSA also asks the Commission to direct pipelines to unbundle their costs into the smallest service components practicable. NGSA states that without the fullest practicable level of cost unbundling, parties may not be able to detect cross-subsidies and the potential for improper pricing will remain.

The Commission believes that it need not amend its

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349. Petition at 9.

350. Petition at 16. It appears that NGSA means Section 284.7(d)(4)(i) and (ii). For example, the former section as proposed to be amended would read: "Any maximum rate filed under this section must be designed to recover on a unit basis, solely these costs which are properly allocated to the unbundled service to which the rate applies."

regulations as suggested by NGSA because sections 284.7(d)(4)(i) and (ii) require rates to be based on the costs which are properly allocated to the service to which the rate applies. This covers all Part 284 services offered by the pipeline. Those services are unbundled from sales. Further, in Order No. 636, the Commission required the pipelines to identify the costs associated with the discrete elements of "no-notice" transportation service, such as the cost of any system storage or imbalance services.[351] The Commission believes that these existing requirements are adequate to satisfy NGSA's request and no further requirements are necessary at this time.

Northwest asks the Commission to clarify that customers should only be required to pay for the particular unbundled services (*e.g.*, gathering, transportation, and storage) that the customers use, and that customers should not subsidize services that they are not using. Similarly, Phillips maintains "that a pipeline may not use a cost allocation or rate design methodology for upstream facilities to gain price advantages for the pipeline's merchant function or to gain competitive advantages for pipeline-owned upstream services over third party providers of upstream services."[352]

As stated above, the Rate Design Policy Statement remains applicable to issues other than the apportioning of fixed costs to the reservation and usage charges. Order No. 636 dealt only with that issue and not with issues such as whether gathering and other production area services, such as processing and production area transportation, should be offered as separate

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351. Order No. 636 at p. 30,422.

352. Petition at 7. See also Natural Gas Clearinghouse, CPUC, and Arizona Direct Customers.

services with separately charged rates.[353] That is still a matter for individual pipeline rate proceedings. However, the Commission repeats its strong preference for fully unbundled services.[354]

I. Interruptible Rate Design

The Industrial Groups[355] contend that the Commission erred in leaving the issue of interruptible rate design (particularly the 100% load factor design) to proceedings under the Commission's Rate Design Policy Statement.[356] They argue that fixed costs should not be attributed to interruptible transportation because such costs are incurred to meet firm, not interruptible requirements. They further contend that maintaining historically high maximum interruptible service is unjustified since the quality of interruptible rates will decline due to the increased use of firm transportation under capacity release and mid-month bumping of interruptible transportation by firm transportation. The KCC, on the other hand, requests that fixed costs should still be allocated to interruptible customers when interruptible volumes flow during peak periods on pipelines with excess capacity.[357]

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353. Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295 at p. 62,059 (1989), *order on reh'g*, 48 FERC ¶ 61,122 (1989).

354. *Id.* and Panhandle Eastern Pipeline Co., 59 FERC ¶ 61,264 (1991), *order on reh'g*, 59 FERC ¶ 61,244 (1992).

355. Petition at 25-28.

356. Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295 (1989), *on rehearing*, 48 FERC ¶ 61,122 (1989).

357. Petition at 2.

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The Commission grants rehearing and directs that issues involving the appropriate rate design for, and allocation of costs to, interruptible transportation must be addressed in the restructuring proceedings.

VII. PIPELINE SALES

Order No. 636 issues blanket certificates to open access pipelines authorizing firm and interruptible sales for resale. The pipeline will be able to sell gas at market-based rates because Order No. 636 concludes that pipelines have no significant market power as sellers of gas on a unbundled basis. In addition, pipeline unbundled sales service will be afforded pregranted abandonment, and pipelines will be subject to standards of conduct and reporting requirements similar to those imposed in Order No. 497.

On rehearing, the Commission is modifying Order No. 636 to require pipelines to continue to sell gas to their current small sales customers (only) at a rate that is cost-based, for a transitional one-year period.

A. Blanket Sales Certificate

Order No. 636 issues to pipelines providing open access transportation, a blanket certificate authorizing unbundled firm and interruptible sales. Under the Rule, existing bundled firm sales entitlements of the pipeline's customers will be converted to an equivalent amount of unbundled firm sales service and firm transportation rights. During the restructuring proceedings, a firm sales customer can elect whether to continue its contractual relationship with the pipeline under the blanket certificate. Under the new blanket sales certificate, the pipeline's sales obligation will be coextensive with its contractual

obligations and unbundled sales will be afforded pregranted abandonment.

APGA and Citizen Action argue that the Commission erred in eliminating individual sales certificates, agreements, and accompanying rights, including abandonment protection and replacing them with a blanket certificate. The parties assert that unbundled sales under the blanket certificate are inferior to current bundled sales and that the Commission has failed to meet its burden of showing that this is required by the public convenience and necessity as required by section 7 of the NGA. As the Commission explained in sections III and IV above, unbundling is required because bundled sales service violates sections 4 and 5 of the NGA, and the Commission's action here is consistent with those sections of the NGA. The requirements of Order No. 636, including unbundling and pregranted abandonment, are all necessary to assure that Part 284 transportation is performed on a just and reasonable basis with respect to all gas supplies. As further explained above, the Commission's action under section 5 is not a revocation of the certificate. The pipeline's certificate obligations with respect to individual services are subsumed into the new blanket certificate with just and reasonable terms consistent with the Commission's findings here.

OkTex Pipeline Company (OkTex) argues that the Commission cannot require a pipeline to accept a certificate of public convenience and necessity[358] and cannot require a pipeline to perform a service it does not seek to perform or that is outside the scope of its business undertaking. OkTex asks the Commission to clarify on rehearing that it will not be required to accept a blanket sales certificate, and will not be subject to

358. OkTex cites, *inter alia*, Associated Gas Distributors v. FERC, 824 F.2d 981, 1041 (D.C. Cir. 1987).

the standards of conduct or reporting requirements simply because it could have accepted a certificate or may elect to do so in the future.

The Commission grants the clarification. Order No. 636 does not require a transportation-only pipeline to engage in sales. Because the standards of conduct in section 284.286 address the relationship between a pipeline's transportation service and its merchant function, they are not relevant to a pipeline that does not engage in sales.[359]

United asks the Commission to clarify that a pipeline will only be required to offer an unbundled sales service to its current sale-for-resale customers up to the currently certificated sales levels applicable to each customer at the delivery points where such service is currently provided. United argues that to go beyond this would be contrary to section 7 of the NGA by imposing certificate obligations which have not been requested by the pipeline and by compelling a service the pipeline is not able to perform.

The Commission clarifies that during restructuring the pipeline's current firm sales customers can elect whether to continue their contractual relationship for gas sales with the pipeline under the blanket sales certificate. The pipeline must continue to provide sales service to its current customers who elect to continue their contractual relationship for gas sales with the pipeline, until the contract expires. This service will be authorized under the pipeline's blanket sales certificate. As such, sales will be unbundled and made at a point upstream and not at the currently certificated delivery points for sales. The obligation

359. If, however, a pipeline chooses to engage in sales in the future, it must file appropriate tariff sheets and comply with the standards of conduct and reporting requirements.

to transport gas will go to the existing delivery points, but in accordance with the rules governing flexible delivery points, the pipeline cannot require deliveries only to existing delivery points.

B. Pricing

Order No. 636 permits pipelines offering unbundled sales to adopt a market-based pricing mechanism for their unbundled sales service upon full compliance with the rule. The Commission found market-based pricing would be justified because sales by non-pipeline merchants would be sufficiently competitive with sales by a restructured pipeline to prevent such a pipeline from exercising market power. Requests for rehearing of this portion of the rule were filed by APGA, Gas Company of New Mexico, Northern Distributor Group, Columbia, Tenneco, Citizen Action, National Association of Gas Consumers, the State of Michigan, Marathon, and Industrial Groups.

1. Statutory Authority

APGA, Gas Company of New Mexico, Northern Distributor Group, Citizen Action, National Association of Gas Consumers, and Marathon allege that the light-handed regulatory approach adopted in Order No. 636 goes too far and constitutes unauthorized deregulation of pipeline sales. These parties point out that the primary purpose of the NGA is to protect consumers from exploitation by natural gas companies[360] and to assure consumers an adequate supply of gas at a reasonable price.[361]

360. APGA and Gas Company of New Mexico cite FPC v. Tennessee Gas Transmission Co., 371 U.S. 145, 154 (1962).

361. APGA and Gas Company of New Mexico cite Tejas Power Corp.

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While conditions in the natural gas market may have changed, they argue that these statutory responsibilities have not. These parties argue that neither the NGPA nor the Wellhead Decontrol Act deregulates sales for resale and that the Commission cannot lawfully execute its responsibilities in a manner that is tantamount to deregulation.[362]

The Commission has considerable flexibility in selecting the methodology it will use to determine just and reasonable rates.[363] No single rate method need be followed and the Commission does not have to adhere rigidly to a cost-based determination of rates.[364] As the Court stated in *FPC v. Hope Natural Gas Co.*, "[u]nder the statutory standard of just and reasonable, it is the result reached, not the method employed, that is controlling."[365]

The courts have recognized that an agency may move from

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v. FERC, 908 F.2d 998, 1003 (D.C. Cir. 1990).

362. APGA cites Maislin Industries, U.S. Inc. v. Primary Steel, Inc., 497 U.S. 116 (1990); Mid-Louisiana Gas Co. v. FERC, 664 F.2d 530, 535 (5th Cir. 1981), *vacated and remanded on other grounds*, Public Service Comm'n of New York v. Mid-Louisiana Gas Co., 463 U.S. 319 (1983); Public Service Comm'n of New York v. FPC, 511 F.2d 338, 354 (D.C. Cir. 1975); and Texaco, Inc. v. FPC, 474 F.2d 416, 423 (D.C. Cir. 1972), *vacated and remanded on other grounds*, 417 U.S. 380 (1974).

363. *E.g.*, FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944); Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

364. *E.g.*, Wisconsin v. FPC, 373 U.S. 294, 309 (1963); FERC v. Pennzoil Producing Co., 439 U.S. 508, 517 (1979).

365. 320 U.S. 591, 602 (1944).

a cost-based approach to ratemaking to a less stringent approach in certain circumstances, and rely on competition to restrain rates.[366] In *Farmers Union Central Exchange, Inc. v. FERC (Farmers Union II)*,[367] although the court rejected the Commission's generic rate-making methodology for oil pipelines in that case, the court recognized that changing characteristics of regulated industries may justify an agency's decision to take a new approach to determining just and reasonable rates. As the court stated, "[m]oving from heavy to light-handed regulation within the boundaries set by an unchanged statute can be justified by a showing that under current circumstances, the goals and purposes of the statute will be accomplished through substantially less regulatory oversight."[368] The court further explained that non-cost factors may play a role in setting rates, if the Commission specifies the nature of the non-cost factors and how they justify the rate.[369] These non-cost factors include competitive forces. As the court stated in *Wold Communication, Inc. v. FCC*,[370] an agency may allow the marketplace to substitute for direct regulation in appropriate circumstances.

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366. *E.g.*, Farmers Union Central Exchange, Inc. v. FERC (Farmers Union II), 734 F.2d 1486 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 1034 (1984); Wold Communication, Inc. v. FCC, 735 F.2d 1465, 1475 (D.C. Cir. 1984).

367. 734 F.2d 1486 (D.C. Cir. 1984).

368. *Id.* at 1510.

369. *Id.* at 1503.

370. 735 F.2d 1465, 1475 (D.C. Cir. 1984); *see also* FCC V. WNCN Listeners Guild, 450 U.S. 582 (1981) (approving FCC reliance on market forces in entertainment programming); Western Union Telegraph Co. v. FCC, 674 F.2d 160 (2d Cir. 1982) ("newly unleashed market forces" may be a reasonable substitute regulatory tool).

The Commission's action here falls within its discretion, as discussed in these decisions, to change its regulatory methods to allow the marketplace to substitute for direct regulation of sales for resale rates. Consistent with *Farmers Union II*, in the final rule, the Commission identified and discussed in detail the changed conditions in the industry that warrant less oversight of sales rates.[371] As discussed more fully below, the Commission found that, with full open access transportation, pipeline *sales markets* are or will be sufficiently competitive to prevent pipelines from exercising monopoly power. The Commission reached this conclusion because, under the final rule, pipelines will offer transportation on an equal basis for all gas supplies and because adequate gas supplies exist throughout the nation from a wide variety of sellers. And this approach puts the pipelines as merchants on the same basis as other sellers of gas now are, *i.e.*, they have the ability to sell gas at market-based rates.

The final rule puts into effect on an industry-wide basis for natural gas sales, the approach to rate regulation that the Commission has adopted recently on a case-by-case basis. In several recent decisions, the Commission approved market-based unbundled sales rates where the Commission found the market to be sufficiently competitive to prevent the pipeline from exercising monopoly power and to keep rates at a just and reasonable level.[372] In *Transwestern Pipeline Co.*,[373] the Commission approved the pipeline's proposal for market-based rates for unbundled sales service because those sales were made in the wellhead market which Congress sought to deregulate.

371. Order No. 636 at p. 30,394-406, 30,408-13, 30,437-41.

372. *See* Order No. 636 at p. 30,439 n.213.

373. 53 FERC ¶ 61,298 (1990).

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Again in *El Paso Natural Gas Company*,[374] the Commission approved a settlement providing for market-based rates for unbundled sales. The Commission found that approval of these rates was consistent with its responsibility to assure that rates are just and reasonable. The Commission explained that in the NGPA, Congress determined that the sales market for gas at the wellhead is competitive and that Congress specified that the price of gas sold in that market is just and reasonable.[375] The Commission found that there are adequate divertible supplies of gas in the markets that El Paso serves and that El Paso sales would compete with deregulated sellers in the wellhead market. The Commission concluded that the competitive wellhead market would force El Paso to charge rates at or below the rates of its wellhead competitors, and, therefore, that the market would operate to keep El Paso's unbundled sales rates at a just and reasonable level.[376] Based on the Commission's findings in these proceedings and on its analysis of the current gas sales market discussed in Order No. 636 and below, the Commission has concluded that its policy of relying, to the maximum extent possible, on competitive market forces to balance the supply and demand for natural gas at reasonable prices should be extended to all sales markets.[377]

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374. 54 FERC ¶ 61,316, *reh'g granted in part*, 56 FERC ¶ 61,290 (1991).

375. § 601(b) NGPA, 15 U.S.C. § 3431(b).

376. *See also* Transcontinental Gas Pipeline Corp., 55 FERC ¶ 61,446 (1991), *order on reh'g*, 57 FERC ¶ 61,345 (1991).

377. In addition, in Buckeye Pipe Line Company, a case involving oil pipeline transportation rates, the Commission held that clearly identified non-cost factors such as competition or a lack of market power warranted departure

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In arguing that the Commission has exceeded its authority, APGA relies on *Maislin Industries, U.S. Inc. v. Primary Steel, Inc.*,[378] where the Supreme Court stated that, although the agency had the experience and expertise generally to adopt new policies when faced with new developments in the industry, "it does not have the power to adopt a policy that directly conflicts with its governing statute." In *Maislin*, the Court rejected an agency decision that was a direct violation of the filed rate doctrine, was contrary to over a century of case law, and permitted the very type of price discrimination that the statute was intended to prevent.

In the Commission's judgement, the situation here is quite different. The final rule does not directly conflict with any statutory mandate. Indeed, the final rule furthers statutory goals by moving toward less stringent regulatory oversight of sales rates within the bounds of the statute. The NGA specifically envisions that individualized contracts will provide terms and conditions for the sale of gas[379] and this rule returns to reliance on individualized contracts to determine the price provision.

In addition, APGA cites *FPC v. Texaco*,[380] as supporting

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from traditional rate review when the substitute ratemaking methodology ensures that resulting rate levels are justified by non-cost factors. 44 FERC ¶ 61,066 (1988), *reh'g denied*, 45 FERC ¶ 61,046 (1988). In the area of electric rates, the Commission has also adopted market based pricing when the electric company lacks market power. *E.g.*, Enron Power Enterprise Corp., 52 FERC ¶ 61,193 (1990).

378. 497 U.S. 116 (1990)

379. United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1955).

380. 417 U.S. 380 (1974).

the proposition that the Commission cannot rely solely on market forces to assure that pipeline rates are just and reasonable, non-discriminatory, and non-preferential. In that case, the Supreme Court, in providing guidance on remand, stated that in its view, the prevailing price in the market cannot be the final measure of a just and reasonable rate. That decision was rendered, however, before enactment of the NGPA and the Decontrol Act. As the Commission has explained, those statutes have changed the nature of the wellhead market and its effect on competition in the pipeline sales market. In any event, the Commission is not simply allowing the prevailing market price to be the determinant of just and reasonable rates. As discussed below, the Commission will monitor the operation of the market through reporting requirements and the complaint process. In addition, the Commission is continuing to regulate jurisdictional transportation on a cost basis.

APGA and Gas Company of New Mexico also cite *Mid-Louisiana Gas Co. v. FERC*,[381] as standing for the proposition that the agency must administer its statute, and may not alter the statutory scheme, even if its alteration is an improvement. In addition, these parties cite *Public Service Comm'n of New York v. FPC*,[382] as holding that where Congress has prescribed regulation, the agency may not "abandon [its] responsibility by acquiescing in a charade or rubber stamping of non-regulation in agency trappings."[383] The Commission has not altered the

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381. 664 F.2d 530, 535 (5th Cir. 1981), *vacated and remanded on other grounds*, Public Service Comm'n of New York v. Mid-Louisiana Gas Co., 463 U.S. 319 (1983).

382. 511 F.2d 338, 354 (D.C. Cir. 1975).

383. APGA also cites Texaco, Inc. v. FPC, 474 F.2d 416, 423 (D.C.

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statutory scheme, but, as explained more fully below, has changed its regulatory methods to police the functioning of the market.

2. Adequate Divertible Supplies

APGA, Citizen Action, Marathon, and State of Michigan argue that the Commission's finding that adequate divertible supplies of gas exist in all markets is not based on substantial evidence. APGA and Marathon assert that there is no record evidence to support this finding. Instead, they argue, the Commission merely concluded generically that, at present, gas supplies in the United States exceed demand and relied on the Decontrol Act. APGA alleges that the Commission made no study of specific gas supply markets, and made no specific findings that there is competition between pipelines and third party suppliers to supply the peaking requirements of temperature sensitive loads. Marathon asserts that a finding of divertible gas supplies on individual pipelines cannot be "scaled-up" to justify an industry-wide finding.

The Commission's finding that there are adequate divertible supplies of gas is based, not only upon its findings in the specific cases discussed above,[384] but also on a detailed analysis of

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Cir. 1972), *vacated and remanded on other grounds*, 417 U.S. 380 (1974), for the same proposition, *i.e.*, that only Congress and not the agency can deregulate.

384. As discussed above, the Commission engaged in a detailed analysis of the gas sales markets in the Transwestern, El Paso, and Transcontinental proceedings.

conditions in the natural gas market.[385] The order relies on the Staff Study on Interim Gas Supply Charges and Interim Gas Inventory Charges, Notice of Proposed Policy Statement, "Use of Spot Market Prices for Sales Service and Gas Inventory Charges."[386] In that study of the national spot market, Staff concluded that the natural gas spot market is a well functioning market in the sense that it is broad, and prices indicate its responsiveness to supply and demand. In addition, Order No. 636 discussed the Staff study on market centers, Importance of Market Centers, Office of Economic Policy, FERC, August 21, 1991).[387] These studies of the natural gas sales market support the Commission's conclusion that there is a significant amount of uncommitted natural gas at competitive prices throughout the country.[388] Further, as part of its analysis, the Commission explained that in passing the NGPA and the Decontrol Act, Congress found that gas sales at the wellhead, or in the field, are competitive.

Thus, the Commission's finding that adequate divertible gas supplies exist in all markets is fully supported by the record in this proceeding. None of the parties has offered any specific evidence to the contrary. Moreover, as discussed more fully below, the Commission has provided parties an opportunity to challenge this generic finding with regard to a specific pipeline in the individual restructuring proceedings.

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385. *See* Order No. 636 at p. 30,394-406, 30,408-13, 30,437-41.

386. Order No. 636 at p. 30,396 n.41, *citing* 47 FERC ¶ 61,294 Appendix at 62,036-62,040 (1989).

387. Order No. 636 at p. 30,427 n.145.

388. Order No. 636 at p. 30,440.

Marathon also argues that the Commission presented no economic theory or legal justification for its conclusion that the existence of adequate divertible supplies *ipso facto* equates to a lack of market power. Contrary to this assertion, the Commission has explained the legal and economic basis for concluding that the existence of adequate divertible supplies of natural gas will prevent the pipeline from exercising market power over unbundled sales. With high quality, open access, firm transportation available, sellers of uncommitted gas supplies will be able to compete with pipeline sales and, as a result, it will not be profitable for a pipeline to attempt to expand its market power over transportation into sales. Pipelines will have to charge rates that compete with the rates of their unregulated competitors, and their rates will be constrained by the rates of their wellhead competitors at a price that Congress has declared to be just and reasonable.[389]

State of Michigan asks the Commission to clarify what it means for a market to be "sufficiently competitive." Further, State of Michigan asserts that while divertible supplies may exist in the current market, they may not exist in the future.

In the final rule, the Commission stated that a pipeline's sales are made in a sufficiently competitive environment when the pipeline provides transportation service of equal quality with respect to all gas supplies, from whomever purchased, and when adequate divertible gas supplies exist.[390] The relevant determination is whether the pipeline is able to exercise market power by controlling prices or excluding competition. A pipeline has significant market power if it can maintain its price above

389. § 601(b) NGPA, 15 U.S.C. § 3431(b).

390. Order No. 636 at p. 30,403 n.71.

the competitive level and obtain a monopoly profit.[391] A market is sufficiently competitive if it prevents the pipeline from exercising market power and operates to keep rates at a just and reasonable level.

The final rule is based on an assessment of present market conditions. It is not necessary for the Commission to find that there will be adequate divertible supplies forever into the future in order to substantiate that the natural gas sales market is competitive. Although the Commission cannot guarantee that demand will never exceed supply, a properly functioning market is the best method for correcting such shortages through changes in the price of gas. And more importantly, the Commission's past price control over the gas commodity was equally no guarantor of "adequate divertible supplies forever."[392] The regulatory approach adopted here permits the Commission to monitor the gas sales market and take corrective action if necessary.

3. Small Customer Rate

APGA and Citizen Action argue that the Commission should impose a price cap on the market-based rates.[393] Industrial Groups argue that before instituting market-based pricing, the Commission should provide for a two-year transition period.

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391. *See* El Paso, *supra*, 56 FERC at 62,175 (1991).

392. *See, e.g.*, Federal Power Commission Order No. 467-B, 49 FPC 583 (1973) (establishing procedures for curtailments during gas shortages).

393. These parties note that even the FCC, when it found that ATT operated in a fully competitive environment, instituted price cap regulation rather than total deregulation.

In addition, APGA argues that even if the market is competitive as to large buyers, the Commission cannot make such a finding as to smaller LDCs on the basis of the record in this proceeding. APGA maintains that the Commission made no finding that there are adequate supplies and adequate competition to serve small sales customers, who have traditionally had fewer gas supply options. APGA further asserts that the Commission could not make this finding based on a full record in the El Paso global settlement, and therefore cannot do so here. Moreover, APGA argues, the Commission has improperly placed the burden of proof on the small LDCs to challenge this finding in the restructuring proceedings, when the burden should be on the pipelines to show that adequate divertible supplies exist to meet the peak-day needs of these customers. Citizen Action maintains that the Commission failed to address the issue raised in the comments on the proposed rule that there is no real competition between pipelines and third party suppliers to supply firm peaking gas.

In the El Paso proceeding cited by APGA,[394] which involved a GIC to be applied only to the pipeline's five largest customers, the competitiveness of the market with respect to small LDCs was not relevant to the issues before the Commission and, therefore, no findings were made as to the competitiveness of that market.[395] The Commission believes that small customers can benefit from purchasing gas in the competitive market as well as large customers. For example, at the technical conference held on January 22, 1992, Florida Cities pointed out that small customers can band together to purchase gas. In Florida, several

394. 54 FERC ¶ 61,316 (1991), *reh'g granted in part*, 56 FERC ¶ 61,290 (1991).

395. *Id.* at 61,945-46 (1991)

municipal utilities banded together with one party buying on behalf of others. The Florida Cites representative at that technical conference reported to the Commission that those utilities have achieved "tremendous economies and urged the Commission to complete the transition to fully unbundled services."[396]

Nonetheless, the Commission recognizes that small customers may require a transitional period to adjust to purchasing gas at negotiated prices. For a one-year period after the effective date of the blanket certificate, the Commission will require pipelines to offer to sell gas to the small customers on their system at cost-based rates. This means that if the customer chooses, the pipeline is obligated to sell gas under the blanket certificate to the small customer on a cost basis for one year from the effective date of the pipeline's blanket sales certificates issued pursuant to Section 284.284. Small customer is defined, for the purposes of this provision, as a customer that purchases gas under the pipeline's one-part imputed load factor rate schedule on the effective date of the blanket certificate. The small customer must exercise this transitional option to purchase gas at a cost-based rate in the restructuring proceeding and not at a later time within the one-year period.

The Commission will not adopt a particular small customer pricing method, but will leave the development of this mechanism to the parties in the restructuring proceeding. There are a number of ways the parties could develop cost-based rates for sales to small customers. For example, the parties could devise a small customer rate using the spot price index. The pricing mechanism could provide that the sale price to small customers would be equal to the spot price plus a fixed amount,

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396. Technical Conference Tr. 277, 291-92, 293. Order No. 636 at p. 30,411.

with the price capped at cost.[397] Alternatively, the parties could provide for periodic adjustments to the sales rate, without reference to a pricing index, by establishing a fixed rate that is adjusted periodically to reconcile any difference between that rate and the pipeline's actual gas costs. The Commission, however, will not permit the continued use of the existing PGA mechanisms for this purpose. The accounting and filing requirements of those mechanisms, as well as the detailed Commission review, are far more complicated than necessary for this one-year transitional measure. Another, simpler alternative would be for the pipeline to establish a fixed gas cost rate for the small customers, without any adjustments during the year, based on a projection of the pipeline's actual gas costs for the year. Or, the parties could agree to a "most favored nations" pricing provision so that the small customer's rate is equivalent to the negotiated price at which the pipeline sells to other customers.[398]

Whatever method the parties choose for establishing the cost-based rate, the pipeline is required to include the method in the tariff sheets filed as part of its compliance filing in the restructuring proceeding. However, this provision will terminate automatically after the one year transition period. Also, regardless of the mechanism the parties develop to establish rates for small customers, sales to small customers must be unbundled. However, as explained above, a customer can contract with the pipeline for the pipeline to act as the customer's agent in packaging the separate services.

The purpose of this limited transitional measure is to allow

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397. See Transwestern Pipeline Company, 55 FERC ¶ 61,519 (1991), for an example of this approach.

398. *See* El Paso Natural Gas Co., 54 FERC at p.61,958.

small customers additional time to make alternate supply arrangements, for example, to arrange to aggregate their purchases. Some municipal LDCs may need to obtain authorization from their state legislature to join into alternate purchase arrangements. The one-year transition period (from the effective date of the pipeline's blanket certificate) will afford these customers sufficient time to determine what alternate arrangements are best suited to their needs and to take measures to implement these arrangements. As a practical matter, this provision will give the small customers a transition period of two winter heating seasons to make these arrangements because the implementation schedule makes it unlikely for most pipelines to have a blanket sales certificates that is effective during the 1992-1993 heating season. The blanket certificate issued under section 284.284 of the regulations requires the pipeline to continue sales to its sales customers if they choose to purchase from the pipeline for the duration of their existing contract term, and the provision adopted here establishes that these sales will be capped at cost to the small customers for a one-year transition period. This certificate authority for sales with cost-based rates to small customers, and any associated tariff provisions, shall terminate automatically at the end of the twelve-month period on a self-executing basis. If, at the end of the one-year period, a small customer must still obtain state legislative action or approval to enter into alternative purchase arrangements (for example, to join a gas procurement cooperative), the small customer may petition the Commission for an extension of the certificate authority for sales to it with cost based rates by the pipeline for a period up to an additional twelve months. The extension would allow the small customer additional time to seek such legislative action or approval during the next scheduled session of its state legislature. Other parties, including the pipeline, will be provided an opportunity to respond to such a petition.

Appendix C

It should be observed that a cost-based rate cap may not afford the small customers the protection they believe will occur. Under the NGPA, pipelines are guaranteed passthrough of actual costs, and experience has shown that the pipelines' regulated resale rates, through the PGA, have been above the market price. As the Commission explained in Order No. 636, purchasers of gas from pipelines have been disadvantaged under the current system. The price that pipelines charge for gas has been 20 to 80 cents higher per mcf than the rates available from other sellers. The so-called protections of traditional cost-based rate regulation have become less significant in the more competitive environment where the market operates to keep prices at a competitive level. Hence, the Commission believes that small customers will be better off purchasing gas under the revised regulatory regime of Order No. 636 than under the current regulations. However, given the limited resources many small customers have, the Commission finds it reasonable to allow this transition mechanism.

With regard to other sales customers, the Commission finds that competition in the market monitored by the reporting requirement and the complaint process will assure that rates are at a just and reasonable level. Therefore, the Commission finds that a general rate cap for all sales, or a general transition period for all customers, is not necessary.

In sum, the provisions of this rule, taken together, will assure that small customers will have access to gas supplies at the lowest reasonable prices. For a one-year transitional period, gas supplies can continue to be purchased from the pipeline at cost-based rates (to the extent the small customer chooses to do so.) However, the small customers will have the opportunity to obtain even better prices in the market. Under the capacity releasing

provisions,[399] customers will be able to obtain the transportation capacity necessary on connecting pipelines to connect them with a source of gas at the wellhead. During the restructuring proceeding, the pipeline that has been providing these customers with bundled sales service will be required to assign its converting upstream firm transportation capacity to its firm transportation customers. This includes the small customers, who can obtain the firm rights to any capacity necessary to give them a direct path to the production area. In addition, after the restructuring period, the provisions of Section 284.243 will give small customers flexibility (acting alone or together, or through a representative) to obtain additional released firm capacity on other pipelines or segments for access to a variety of sources of supply as they become available. Thus, the rule provides sufficient flexibility and safeguards to assure continued reliable service to small customers at reasonable rates.

4. Regulatory Safeguards

Marathon asserts that in order to assure that light-handed regulation achieves statutory goals, the courts have required certain safeguards. Marathon argues that the Commission erred in failing to provide adequate safeguards to assure that rates will fall within a zone of reasonableness, and failing to provide for an administrative remedy if they do not.[400] Marathon asserts that the complaint procedure is not an adequate safeguard

399. Sections 284.242 and 284.243.

400. Marathon cites, *inter alia*, Public Service Company of Indiana, 51 FERC ¶ 61,367 at 62,223 (1990) (where the Commission stated that the Farmers Union II court found that the flaw in the Commission's market based regulation was that "nothing in its regulatory scheme would act as a monitor either to determine whether competition would drive prices down ... or to check rates if it did not.").

because it places the burden of proof on the party challenging the rate, and because the Commission cannot execute its responsibilities by relying on contesting parties to bring problems to the Commission's attention.[401] Similarly, Northern Distributor Group argues that section 5 is not an effective remedy because of regulatory lag and the prospective nature of the section 5 remedy.

While the Commission has found that market-based rates are appropriate for pipeline sales, the final rule recognizes that there may be some isolated markets that are not sufficiently competitive to support a finding that a particular pipeline lacks significant market power. Thus, the Commission stated that the parties may raise the issue of a particular pipeline's market power in the restructuring proceedings. If a party to the restructuring proceedings demonstratesthat the pipeline has significant market power over the sale of gas, the Commission will employ more regulatory control, if the pipeline does not rebut this evidence showing. The market-based rates will not be put into effect prior to a Commission examination of a party's argument, so refunds are not an issue in the restructuring proceedings.

If competitive circumstances on the pipeline change, a customer may file a complaint under section 5 of the NGA to show that the pipeline has attained market power and that greater regulatory control is needed. As Marathon notes, in a section 5 proceeding, the complainant has the burden of proof, remedies are prospective only, and no refunds can be ordered. This, however, has always been part of the regulatory scheme as enacted by Congress, and does not render section 5 ineffective as a remedy. The issue of market power will first be examined

401. Marathon cites Tejas Power Corp v. FERC, 908 F.2d 998, 1003 (D.C. Cir. 1990).

in the restructuring proceedings, if raised by the parties, and in the event of changed circumstances, the section 5 procedure is available to an aggrieved party.

Marathon also argues that the Commission has essentially established a rebuttable presumption that all pipelines lack market power, and that this presumption improperly shifts the burden of proof to the contesting party in the restructuring proceedings. Marathon argues that this "ignores the Commission's market power findings in the incentive rate docket and its recent decision to open an investigation of deregulated pipeline transportation." Marathon asserts that in both cases, the Commission observed that market power is an unsettled, largely unexplored issue.

Contrary to Marathon's characterization, the Commission has not instituted an investigation of deregulated pipeline transportation. Instead, a task force has been established to consider how to evaluate competition in transportation markets. Both the task force and the incentive rate proceeding referred to by Marathon involve transportation, not sales, rates. Nothing in the Commission's proposed policy statement on incentive ratemaking[402] or the establishment of a task force on competition in transportation markets evaluates competition in the natural gas sales market or conflicts with the finding that pipelines lack market power over sales of gas.

In addition, Marathon argues, this procedure is inconsistent with the Commission's approach in electric utility cases where

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402. Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Notice of Proposed Policy Statement on Incentive Regulation, Docket No. PL92-1-000, issued March 13, 1992, 58 FERC ¶ 61,287 (1992).

the Commission has required the utility to show that it lacks market power. Since the Federal Power Act and the NGA must be read *in pari materia*, Marathon argues, the Commission must provide a reasoned explanation for departing from its electric utility precedents.

Precedent under the Federal Power Act is relevant to NGA proceedings. However, the electric transmission market has characteristics very different from the natural gas sales market. Electric transmission, like natural gas transportation, has characteristics of a natural monopoly, and competition may not be as effective to restrain prices. Thus, the Commission's approach in electric cases, *i.e.*, an individual inquiry into market conditions in each rate proceeding, is appropriate.

In the natural gas sales market, however, the Commission has found that pipelines no longer have a monopoly over the sale of gas. There are other sellers and marketers of gas in the marketplace, and in order to meet that competition, the pipeline will have to charge rates at or below the prices of its wellhead competitors.

Finally, Marathon asserts, the rebuttable presumption is defective because the pipeline is the party in possession of the necessary facts to show lack of market power, and, consistent with evidentiary principles,[403] should bear the burden of proof. While the pipeline is in possession of the facts concerning its own operations, it does not follow that it should bear the burden of proof on all issues where that information is relevant. If that were the case, the pipeline would bear the burden of proof on every issue in rate cases, but that is not consistent with the

403. Marathon cites, *inter alia*, XI Wigmore on Evidence § 2486, p. 290.

scheme under the NGA. Moreover, facts concerning adequate divertible supplies would not necessarily be within a pipeline's exclusive possession. The data exchange process established by the Commission will permit the parties to obtain information necessary to substantiate their market power claims.[404]

Marathon also argues that the rule is ambiguous as to what the contesting party must prove. Marathon asks the Commission to clarify that the parties will have a full opportunity to challenge anticompetitive sales and show that the pipeline possesses market power, including market power derived through inadequate divertible gas supplies.

The Commission did not intend to limit the matters the parties may raise in the individual restructuring proceeding and clarifies that the parties may address market power based on inadequate divertible supplies as well as on other conditions. However, the Commission will defer the issue of specific evidentiary standards to case-by-case resolution.

Industrial Groups argues the Commission should review tariff sheets filed by each pipeline to determine whether rates are just and reasonable in accordance with Order No. 636 standards. Similarly, APGA, ConEd, Michigan Gas, NYSE&G, Northern Distributor Group, New York PSC, Peoples Gas, and the State of Louisiana argue that the Commission should require as part of the less intrusive regulatory scheme, that pipelines file a rate case every three years to evaluate the justness and reasonableness of unbundled sales and transportation rates. Without this requirement, Northern Distributor Group argues, light-handed regulation becomes deregulation.

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404. See the order issued June 24, 1992 in Docket No. RM91-11-000, granting in part the motion filed by Natural Gas Clearinghouse to establish discovery procedures. 59 FERC ¶ 61,351 (1992).

As discussed more fully below, the Commission will not require the pipelines to file a new rate case every three years. The statute does not require such a filing, and Commission finds no basis for imposing this requirement.

5. Other Matters

Columbia asks the Commission to clarify section 284.14(d)(2) of the regulations which provides that a pipeline may abandon its sales obligations to any purchasers to the extent "[t]he purchaser refuses to pay the rate the pipeline offers for unbundled sales." Columbia maintains that it reads this section as giving pipelines the ability to offer rates that in their sole discretion adequately compensate them for their remaining merchant function. Columbia asks the Commission to clarify that it will not intervene and set a sales rate for a pipeline if any purchaser insists that a pipeline remain a merchant, but refuses to pay the rates proffered by the pipeline.

Columbia's request for clarification is granted. The pipeline will determine whether it wants to sell gas at a particular rate, with the limitation that rates to small customers must be cost-based for a one-year transition period. However, as explained above, the pipeline is subject to the provisions of the NGA, and the Commission will address a customer's complaint that the pipeline is violating the statute.

Tenneco asks the Commission to clarify that pipelines have no more obligations with respect to the sale of gas than other gas merchants. Specifically, Tenneco asks the Commission to clarify that pipelines are free to negotiate all the terms of their sales contracts, and that differences in terms of sales contracts will not constitute undue discrimination.

Individualized contracts between pipelines and customers

are permitted under the NGA,[405] and competitive conditions may justify different contractual terms for sales service. However, the pipeline is still subject to the NGA requirement that pipelines must provide service on a non-discriminatory basis. Thus, similarly situated customers must be treated similarly.

Further, Tenneco argues that there is no justification for the Commission's requirement that pipelines perform agency services on a non-discriminatory basis. Tenneco states that non-pipeline sellers are not required to offer agency services on a non-discriminatory basis, and that there is no evidence that customers desiring agency service will find any shortage of sellers willing to provide this service. Further, Tenneco argues, imposition of this requirement on pipeline sellers, when no such restriction exists for non-pipeline sellers, gives non-pipeline sellers an unfair competitive advantage, and thus harms the unfettered competitive market the Commission is trying to foster.

Tenneco's argument ignores a critical difference between pipelines and non-pipeline merchants: the pipelines are in control of the operations of the transportation grid and they are, simply put, different from other merchants, since they are the only merchants in control of pipeline capacity. Pipelines are still subject to the NGA and may not unduly discriminate among customers. Pipelines are encouraged to offer an agency service, and this service must be offered on a non-discriminatory basis. Competitive circumstances, however, can justify differences among customers.

Further, Tenneco urges the Commission to clarify that if market-based pricing is not approved by a reviewing court for

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405. United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956).

any reason, then the basis of the entire rule is no longer applicable. Tenneco's request is denied. The Commission will not speculate what action it might need to take in response to a decision by a reviewing court.

C. Standards of Conduct

In Order No. 497, the Commission adopted standards of conduct and reporting requirements for interstate pipelines with marketing affiliates.[406] These regulations implement the Commission's authority to prevent undue discrimination by prohibiting the pipeline from preferring its marketing affiliate over unaffiliated shippers with regard to transportation matters, access to information, and transportation discounts. On July 21, 1992, the U.S. Court of Appeals for the District of Columbia Circuit upheld in substantial part the Commission's decision in Order Nos. 497 and 497-A. The court found that the standards of conduct and reporting requirements are an appropriate exercise of the Commission's authority to prohibit undue preferences, but found that the Commission had not adequately

406. Inquiry into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, Order No. 497, 53 FR 22139 (June 14, 1988, FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,820 (1988), *order on reh'g*, Order No. 497-A, 54 FR 52781 (December 22, 1989) FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989), *order extending sunset date*, Order No. 497-B, 55 FR 53291 (December 28, 1990) FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990), *order extending sunset date and amending final rule*, Order No. 497-C, 57 FR 9 (January 2, 1992) III FERC Stats. and Regs. ¶ 30,934 (1991), *reh'g denied*, 57 FR 5815 (February 8, 1992, 58 FERC ¶ 61,139 (1992). The United States Court of Appeals for the District of Columbia Circuit upheld the Commission's decision in substantial part in Order Nos. 497 and 497-A in Tenneco Gas Co. v. FERC, No. 89-1768 (July 21, 1992).

explained its extension of the contemporaneous disclosure requirement to gas sales and marketing information and remanded that issue to the Commission for further explanation.[407]

Order No. 636 does not change the requirements governing the relationship between pipelines and their marketing affiliates. However, Order No. 636 extends the requirements to pipelines providing unbundled gas sales services because the pipeline as merchant will be the functional equivalent of a marketing affiliate. Requests for rehearing of this portion of Order No. 636 were filed by several pipelines[408] and other parties.[409] Generally, the pipelines argue that the Commission erred in continuing the Order No. 497 requirements and applying them to pipelines as merchants, while the other parties maintain that additional protections are required.

CNG argues that the Commission lacks authority to extend the standards of conduct to pipelines because neither the NGA nor the NGPA specifically authorizes the Commission to require the separation of a pipeline's employees or to control the dissemination of business information. However, as the Commission explained in Order Nos. 497 and 636, there is obvious potential for undue discrimination by the pipeline to favor its own merchant function or its marketing affiliate. The Commission's jurisdiction to remedy undue discrimination is broad and is not limited to specific measures set forth in the

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407. The Court also found that the Commission erred in finding Order No. 497 applicable to Ozark Gas Transmission System (Ozark).

408. Alabama-Tennessee, Arkla, CNG, K N Energy, Natural, Northwest, Tenneco, and Texas Gas.

409. Hadson and IPAA.

NGA or the NGPA.[410] In any event, the court's decision in *Tenneco* v. *FERC* largely answers CNG's jurisdictional argument and establishes that these regulations are within the scope of the Commission's authority.

Further, CNG argues, even if the Commission had authority to impose the requirements, it would need a factual basis to justify their adoption. CNG, Alabama-Tennessee, Arkla, K N Energy, and Tenneco argue that there is no finding based on substantial evidence that anticompetitive practices exist now or will after the restructuring. The parties assert that the Commission's concern that pipelines would favor their own sales is inconsistent with the Commission's finding that pipelines cannot exercise market power over sales and that all sellers will compete on an equal footing after restructuring. Tenneco argues that the rule will not be necessary after restructuring because the Commission's regulations will prohibit discrimination, and because matters addressed in the restructuring proceedings, including nondiscriminatory terms and conditions for unbundled transportation, allocation of receipt and delivery point capacity, and the electronic bulletin board will ensure that pipelines cannot give the merchant arm or their marketing affiliate any undue preference. Similarly, Alabama-Tennessee argues that there is no need for this protection because transportation is rapidly becoming the dominant pipeline service. K N Energy argues the Commission should modify the rule to provide that the standards of conduct will not apply unless the Commission finds that the pipeline is acting in a discriminatory manner.

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410. *E.g.*, FPC v. Louisiana Power & Light Co., 406 U.S. 621 (1972),; FPC v. Conway Corp., 426 U.S. 271, 279 (1976); Colorado Interstate Co., 324 U.S. 581 (1945), Associated Gas Distributors v. FERC, 824 F.2d 981, 997-1001 (D.C. Cir. 1987).

Appendix C

In explaining the need for the standards of conduct in Order No. 497, the Commission pointed to the potential for abuse, actual instances of anticompetitive practices, and allegations of unlawful practices that had come to its attention. The Commission concluded that the pipelines have economic incentives to show undue preferences toward their affiliates and the court has agreed that this warranted Commission action.[411] Unbundling, as required by Order No. 636 does not eliminate the potential for pipelines to favor their marketing affiliate because, as the Commission explained in Order No. 636, there is no change in the pipeline's control of the transportation function. Further, the same potential for abuse exists with regard to the pipeline merchant function and it is therefore appropriate to apply the standards of conduct to pipelines exercising the merchant function.

The Commission recognizes, however, that abuses in the area of marketing affiliates might not be a perpetual problem, and that increased competition that will result after unbundling may reduce the incentive for abuse. Order No. 497 adopted a sunset provision specifying that the Commission's reporting requirements would expire after one year unless reauthorized. The Commission has extended the sunset date of the regulations three times because it found that Commission monitoring was still necessary. As discussed below, the Commission intends to address this issue in the near future.

Several pipelines argue that the regulations would impose severe administrative, logistical, and financial burdens on the pipelines and would place them at a competitive disadvantage with respect to other sellers of gas. CNG focuses on the

411. Order No. 497, FERC Stats. and Regs. [Regulations Preambles 1986-1988] ¶ 30,820 at p. 31,129 (1988), *aff'd* Tenneco v. FERC,*supra*.

requirements that pipelines must make available to all potential shippers any information it gives an affiliate regarding transportation matters and that the pipeline must, to the maximum extent practicable, provide for the independent functioning of operating and marketing personnel. CNG alleges that this could require dissemination of virtually all routine information and require that the pipeline divest itself of in-house sales, in effect driving the pipeline out of the marketing business. The pipelines argue that this deprives consumers of the advantages of integrated firms. Tenneco alleges that the rule would require pipelines to divulge sensitive information.

The regulations are not unduly burdensome on pipelines, but instead establish an appropriate balance between the benefits of integration and the potential for anticompetitive abuses. Contrary to the pipelines' contentions, the regulations will not require the dissemination of all routine business information or sensitive information or drive the pipelines out of the merchant business.[412] In Order No. 497, the Commission specifically rejected a proposal to require pipelines to divest themselves of their marketing affiliates and instead adopted a more flexible standard that, as explained below, permits compliance to conform to the particular characteristics of the individual pipelines.

Arkla argues that the standards adopted by the Commission are too vague because they do not give notice to the pipeline of

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412. For example, a pipeline could avoid the possibility of being required to divulge sensitive information by separating its sales operations from transmission operations and requiring that the sales operating unit obtain all of its information about service from the electronic bulletin board. This would place the sales operating unit on exactly the same footing as any other seller.

what is permissible. Arkla asserts that the Commission never provided workable standards for its marketing affiliate rule and makes the same error here. Hadson similarly argues that while the rule requires operating employees of the pipeline transporter and the unbundled merchant to function independently to the maximum extent practicable, it does not define "operating employees," "function independently," or "maximum extent practicable."[413]

The standard adopted by the Commission is designed to permit individual variations in compliance appropriate to the particular characteristics of the pipeline. The application of these standards to the particular pipelines will be considered in the restructuring proceedings. As the Court held in *Tenneco v. FERC*, this does not render the standard impermissibly vague.

Northwest is concerned that the regulations governing no-notice service may have the effect of requiring pipelines to offer sales and become bound by Order No. 497 when they have no desire to engage in sales. In addition, Northwest and Tenneco argue the rule could subject pipelines who are engaged in sales to a few small distributors or as back-up to no-notice service to unnecessary and overly burdensome regulation.

These concerns are unfounded. As explained above, a pipeline is not required to continue providing unbundled sales service if its current bundled sales customers do not request and contract for unbundled sales service, nor is the pipeline required to offer sales service incidental to its no-notice service. Further, as explained below, if a pipeline engages in minimal sales, it can seek a waiver of the requirements.

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413. Hadson notes that it argued in its brief to the court in Tenneco v. FERC, No. 89-1768 (D.C. Cir.) that the failure to define these standards will create problems.

Appendix C

Alabama-Tennessee asserts that, as a small pipeline, it would have to hire additional employees and establish separate and duplicate facilities which could drive it out of the merchant business. Alabama-Tennessee states that the possibility of waivers, as in *Northern Border Pipeline Co.*,[414] will not provide a remedy because even the reduced requirements approved there would be burdensome. It argues that small pipelines should be exempt from the requirement.

As explained in Order No. 636, small pipelines have the same potential for favoring their own sales as do large pipelines, and a general exemption from the requirements for all small pipelines is not warranted. However, the flexible standard of the rule and the Commission's willingness to consider waivers of the regulations in appropriate circumstances assures that the requirements will not be unduly burdensome on small pipelines. Waivers will be considered on an individual basis and Alabama-Tennessee may seek a waiver different in scope than that granted in the *Northern Border* case, *supra*.

Unlike the pipelines, IPAA argues that additional protections are required to prevent affiliate abuse. IPAA argues that the correlative discount requirements of section 161.3(i)[415] now apply to transportation discounts, but that once a pipeline conducts unbundled market-based sales, it could avoid the requirements by selling gas at a loss while charging the maximum transportation rate to deliver the gas. IPAA asks the Commission to clarify the regulations to prevent pipelines from evading the requirements concerning correlative discounts.

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414. 55 FERC ¶ 61,262 (1991).

415. This section provides that if a pipeline offers a transportation discount to an affiliated marketer, it must make a comparable discount contemporaneously available to all similarly situated nonaffiliated shippers.

The Commission believes that IPAA's concern was adequately addressed in Order No. 636. There, the Commission concluded that "Order No. 497's standards of conduct and reporting requirements should apply to the pipeline when it provides unbundled gas sales services."[416] This included the correlative discount requirements of section 161.3(i). As part of the reporting requirements, pipelines are required to report whether affiliate marketer, or the blanket sales operating unit, sell gas below cost.[417] Also, section 250.16(g)(2) requires pipelines to maintain 24-hour public electronic access to this data. Thus, the Commission believes that pipelines will be unable to conceal such arrangements and, as a result, they should not occur.[418] And, in the unlikely event they do occur, they will be open to public scrutiny and could form the basis for action on a complaint to the Commission.

Further, IPAA asks the Commission to amend the regulations to provide that a pipeline should not discriminate between its own sales customers and its no-notice shippers who purchase from a third party. IPAA states that if capacity is preempted by no-notice service, curtailment should be

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416. Order No. 636 at p. 30,442.

417. See 18 CFR 250.16(b)(2)(xiv), which requires a pipeline subject to this rule to file a transportation log containing, *inter alia*, information about whether the affiliated marketer (or blanket sales operating unit) is selling gas at a loss.

418. However, it is important to note that the pattern suggested by IPAA is not, *per se*, a violation of the Commission's standards of conduct. An affiliated marketer (or blanket sales operating unit) may lose money on a specific sale during a specific period because it misjudged the market. A problem exists only when a pipeline grants an undue preference to an affiliate marketer (or blanket sales operating unit).

implemented in a manner which does not favor pipeline affiliate transactions. IPAA urges that this clarification will avoid numerous disputes in the restructuring proceedings.

The Commission will not address this issue here, but will require the parties to address issues related to no-notice service in the restructuring proceedings. However, Order No. 497 with regard to marketing affiliates and Order No. 636 more generally, prohibit discrimination against non-affiliates or preferences for affiliates in the operation of curtailment provisions.

The rule makes pipeline merchants subject to the reporting requirements in section 250.16 of the regulations currently applicable to pipelines with marketing affiliates.[419] Hadson notes that these requirements, by their terms, expire at the end of 1992, before the blanket sales certificates issued under the Restructuring Rule take effect. Hadson suggests that the Commission delete the current provision in section 250.16(d)(1) that eliminates the reporting requirements on December 31, 1992, at least as it relates to the reporting requirement for the instant rule.

As explained above, the Commission recognizes that the potential for anticompetitive abuses may not be a perpetual problem, and, therefore, in Order No. 497 adopted a sunset provision specifying that the Commission's reporting requirements would expire after one year unless reauthorized. The Commission has extended the sunset date of the regulations three times because it found that Commission monitoring was still necessary.[420] As noted above, the court's decision in *Tenneco*

419. 18 CFR 250.16.

420. Order No. 497-A, 54 FR 52781 (December 22, 1989) FERC Stats. (Cont'd)

v. FERC was issued on July 21, 1992, and the rehearing period has not expired. The Commission intends to extend the reporting requirements in the near future when it considers the issues on remand.

Hadson is concerned that there should be a public review process to ensure that the pipeline's procedures comply with the independent functioning standards. Hadson objects to the current process under section 161.3(j), which requires pipelines to file procedures to enable shippers and the Commission to determine how the pipeline is complying with the standards of conduct because, Hadson states, those filings are not noticed in the Federal Register or the Commission's daily orders and because the Commission has ruled that these filings are "non-adversarial." Hadson asks the Commission to resolve these problems by clarifying that (a) all filings made to demonstrate compliance with the law will be noticed in the Federal Register and the daily orders, with reasonable periods of time for members of the public to review the filings and voice facts or concerns; (b) the Commission will review the filings on the basis of a public record; and (c) the Commission will make a determination on the basis of the facts and advocacy in that public record.

The clarification sought by Hadson is unnecessary. Order No. 636 requires the pipelines to file their proposed procedures for compliance with the standards of conduct as part of their

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(Cont'd)

& Regs. [Regulations Preambles 1986-1990] ¶ 30,868 (1989) Order No. 497-B, 55 FR 53291 (Dec. 28, 1990), FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,908 (1990); Order No. 497-C, 57 FR 9 (Jan. 2, 1992), III FERC Stats. and Regs. ¶ 30,934 (1991), *reh'g denied*, 57 FR 5815 (Feb. 8, 1992), 58 FERC ¶ 61,139 (1992).

compliance filing and, therefore, the parties will have an opportunity to address these issues in the restructuring proceedings.

D. Reporting Requirements

In Order No. 636, the Commission required pipelines to file annual reports with respect to their sales under the blanket certificate, but waived the provision of section 154 of the regulations with respect to the filing of the sales prices between the pipeline and each of its sales customers. APGA, Citizen Action, and Gas Company of New Mexico allege that in modifying the reporting requirements, the Commission failed to adopt the minimum safeguard necessary to monitor the existence or abuse of market power. Gas Company of New Mexico maintains that the Commission cannot meet its responsibilities if all it receives is an annual summary of rates.

On the other hand, Tenneco asks the Commission to eliminate all reporting requirements. Tenneco argues that pipelines no longer have a monopoly over the sale of gas so it is unduly discriminatory to impose these reporting requirements only on pipeline sellers of gas.

The final rule requires all pipelines engaging in unbundled sales to file an annual report with the Commission describing the type of service provided, the total volumes sold, and the total revenues received.[421] The Commission waived the requirement that pipelines file sales prices between the pipeline and each of its sales customers. In the Commission's view, the reporting requirement added by this rule satisfies the NGA

421. Section 284.288.

requirements when the purchaser is on notice of the rate, and the amount of total revenues from each purchaser is eventually filed with the Commission as an average price as required by the reporting requirement. This information will provide an indication of how the market is functioning and whether a pipeline has been able to exercise market power.

The Commission believes that the reporting requirement plus the complaint procedure will be an effective means of monitoring the market to assure that the market functions to keep rates at a just and reasonable level. Additional reporting requirements would not aidin this process and would place an unnecessary burden on the pipelines. The most reliable indicator of whether the market is functioning to restrain rates is whether the customers are satisfied that they are receiving adequate service at reasonable rates. Where the market is not functioning to keep rates at a just and reasonable level, the Commission will consider action under section 5 to investigateand provide a remedy.

Tenneco's request that the Commission eliminate all reporting requirements is denied. As explained above, while the rule gives pipelines more flexibility to price their sales services to compete with other sellers and marketers of gas, the Commission will continue to carefully monitor the pipelines sales because pipelines control transportation.

VIII. PIPELINE SERVICE OBLIGATION (AFTER RESTRUCTURING)

Requests for rehearing of the Order No. 636 rules on pre-granted abandonment in sections 284.221(d) and 284.285 have been filed by numerous parties, including industrials, LDCs,

pipelines, and state regulatory agencies.[422] On rehearing, the Commission is modifying Order No. 636 to provide that in exercising its right of first refusal to retain capacity, a long-term firm transportation customer must match the price offered by a competing bidder, up to the maximum just and reasonable rate, and the longest contract term offered by a competing bidder, up to a maximum period of 20 years.

A. Interruptible and Short-term Firm Transportation

Section 284.221(d), promulgated by Order No. 636, authorizes pregranted abandonment of all interruptible and short-term firm transportation. The Commission explained that the nature of these services is such that customers selecting these options do not rely on continued service at the expiration of the contract. On rehearing, AGD and Peoples Gas state that while they have no objection to the application of pregranted abandonment to short-term firm transportation contracts, they ask the Commission to clarify that under the rule, a customer must actually have the option of taking long-term service. Otherwise, they argue, a pipeline could use its market power to coerce the customer into accepting a short-term contract in order to avoid giving the customer the right of first refusal.

Under Part 284 of the Commission's regulations, a pipeline

422. American Paper Institute; Industrial Groups; Reynolds Metal Company (Reynolds); APGA; AGD; Atlanta Gas; Cascade; CNG LDCs; ConEd; Elizabethtown; Illinois Power; New England Gas Distributors; New Jersey Natural; NYSE&G; Northern Distributor Group; Northern Illinois Gas; Northwest Natural Gas Company (Northwest Natural); Peoples Natural Gas; PSE&G; Tennessee and Columbia Small Customers; United Distribution Companies; Wisconsin Distributor Group; ANR; CNG; El Paso; Kern River; Natural; Citizen Action; Maryland People's Counsel; NASUCA; Pennsylvania PUC; State of Michigan.

has never been permitted to use its monopoly power to force certain customers to accept short-term service when they prefer long-term service if capacity is available to provide firm service. Withholding capacity violates the pipeline's obligation to provide transportation as embodied in section 284.8(b) of the Commission's regulations, which requires pipelines offering transportation on a firm basis to provide service "without undue discrimination, or preference, including undue discrimination or preference in the quality of service provided, the duration of service, the categories, prices, or volumes of natural gas to be transported, customer classification, or undue discrimination or preference of any kind."[423]

Peoples Gas also argues that priority interruptible service should receive protection from pregranted abandonment. It notes that some interruptible arrangements between a pipeline and small customers have enjoyed a special status because the Commission has found that these customers depend on these arrangements to meet peak load. Their Authorized Overrun Service from Viking Pipeline is within this group, Peoples Gas states, and has priority over other interruptible service because it is required to meet peak load. Peoples Gas cites *Viking Gas Transmission Company*,[424] where the Commission approved Viking's proposal to include a limited quantity of AOS service in its high priority interruptible service for small customers.

In the *Viking* decision cited by Peoples Gas, the Commission approved the pipeline's proposal because the record in that case showed that Viking was the only pipeline that served the requirements of these customers, that additional firm capacity was not available on the Viking system, and that these customers

423. 18 CFR 284.8(b).

424. 52 FERC ¶ 61,015 at p. 61,106 (1990).

had historically relied on purchases or transportation of interruptible gas to meet peak demands. There is no basis for concluding that these circumstances will exist on any pipeline after restructuring or that Peoples Gas will be unable to contract for firm transportation service. As explained in Order No. 636 and throughout this rehearing order, the rule will result in increased availability of firm capacity. Therefore, the Commission will not provide an exemption from pregranted abandonment for high priority interruptible service. If a customer requires high priority service to meet peak needs, then the customer should contract for firm service from the pipeline and pay the appropriate rate for firm service.

Northern Indiana Public Service Company asserts that the pre-granted abandonment of interruptible transportation could result in preferential treatment and discrimination if pre-Order No. 636 queue priorities are retained. Northern Indiana states that because the rule permits, but does not require pregranted abandonment, it could result in a pipeline's picking and choosing which interruptible shippers might be allowed to continue to use a high priority transportation or storage contract through roll- over or evergreen contract provisions because the pipeline has pre-approved unilateral abandonment rights. Northern Indiana maintains that the way to avoid this problem is to eliminate archaic queue date priority rights.

As the Commission has explained, a pipeline is not required to include a roll-over or evergreen clause in its contracts, but if it does, it must include such clauses on a non-discriminatory basis. Further, pre-Order No. 636 firm transportation queues will not be relevant in determining capacity allocation during the restructuring proceedings. The Commission believes that queues will be less important on the pipelines after restructuring because capacity should become available through the release

mechanism. Interruptible capacity will be posted on the electronic bulletin board.

B. Unbundled Sales

The Final Rule adopted pregranted abandonment for unbundled sales service and explained that a "continuing service obligation is no longer necessary to ensure LDC access to gas supply."[425] Although most parties have no objection to this provision, Marathon asserts that this is the first time the Commission has made access to gas supply the sole factor in determining whether the public convenience and necessity requires continuation of the pipeline service obligation. Marathon argues that while the Commission may change its abandonment standard, it must carefully consider and explain the need for a new standard.[426]

Marathon argues that the Commission has failed to explain why there should no longer be a distinction between private contracts and the statutory service obligation. Further, Marathon argues, while "access to gas supplies" was a major component of the public convenience and necessity in previous abandonments, it was not the only factor. Marathon asserts that the Commission has failed to explain why other factors, such as environmental impact, the presumptions of continued service, the impact on competition, and the public interest have been eliminated. Marathon does not oppose pregranted abandonment of unbundled sales, but argues that the Commission must provide a more detailed explanation of its reasoning.Similarly, Gas

425. Order No. 636 at p. 30,446.

426. Marathon cites, *inter alia*, Greater Boston Television Corp. V. FCC, 444 F.2d 841 (D.C. Cir. 1970), *cert. denied*, 403 U.S. 923 (1971); Consolidated Edison Co. of N.Y. v. FERC, 823 F.2d 630 (D.C. Cir. 1987); and Felmont Oil Corp. and Essex Offshore, Inc., 33 FERC ¶ 61,333 (1985).

Company of New Mexico argues that the Commission has failed to justify pregranted abandonment of sales. Gas Company of New Mexico cites *United Gas Pipe Line Company v. McCombs*,[427] where the Court stated that in that situation, to leave the abandonment determination in the producer's control would be "at odds with Congress' purpose to regulate the supply and price of natural gas."

Contrary to these assertions, the Commission has explained why it finds pregranted abandonment of unbundled sales upon contract expiration or termination to be permitted by the public convenience and necessity and how the factors cited by Marathon relate to that decision. As explained in the final rule,[428] this finding was based partly on the Commission's determination that sufficient gas supplies exist nationwide to prevent pipelines from exercising market power over gas supply at a contract's termination, and, therefore, that individual abandonment proceedings are unnecessary with respect to the pipeline's sales service to protect LDCs and assure continued access to supplies. The parties to a sales contract can defer pregranted abandonment by including evergreen or roll-over clauses in their contracts. In addition, the Commission's objective of creating an efficient and national gas market that protects all users of natural gas will be better served by pregranting abandonment because it will put pipelines sales on a more even, competitive basis with other suppliers. Finally, in Order No. 636, the Commission found that pregranted abandonment would have no significant environmental impact and, therefore, there is no need to consider this as a factor in authorizing service abandonment.[429]

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427. 442 U.S. 529, 539 (1979).

428. Order No. 636 at 30,446-447.

429. Order No. 636 at 30,469.

The *United Gas Pipe Line Co. v. McCombs*[430] cited by Gas Company of New Mexico is inapposite because in that case, the producer attempted to abandon service without first obtaining Commission approval under section 7(b). Here, the Commission has pregranted abandonment on a generic basis and made the required findings to support its conclusion.

C. Long-term Firm Transportation

As the Commission explained in the Final Rule, long-term firm transportation service has characteristics different from interruptible and short-term firm transportation and unbundled sales services, and, thus, the Final Rule establishes a procedure for protecting the legitimate needs of customers for continued service. First, the parties may choose to defer application of pregranted abandonment to their arrangement by including roll-over or evergreen clauses in their service contracts. Second, the right of first refusal at just and reasonable, cost-based transportation rates will protect the customer even if a roll-over or evergreen clause is not included in the contract. Under the right of first refusal, the existing customer will be able to retain service at the expiration of the contract by agreeing to match the highest cost-based transportation rate, up to the maximum rate approved by the Commission, and the longest contractual term offered by another bidder seeking the service.[431]

1. Definition of Long-term Service

The regulations governing the right of first refusal apply to firm transportation pursuant to a contract for a term of more

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430. 442 U.S. 529 (1979).

431. 18 CFR 284.221(d)(2)(ii).

than one year.[432] Industrial Groups and Northern Illinois Gas ask the Commission to amend this definition to provide that an arrangement will be considered long-term transportation if the contract is for a period of one year or more. The parties state that this is consistent with business and commercial realities and the industry procedure and billing practices. Northern Illinois Gas states that the calendar month and year are the basis for most transactions, and the introduction of partial months and carryover days is an unnecessary complication.

These requests are consistent with the Commission's intent and the Commission will amend the rule to make it consistent with industry practice. A long-term transportation service is one that is pursuant to a contract for a term of one year or more.

2. Roll-Over and Evergreen Clauses

In the Final Rule, the Commission explained that the parties can defer application of pregranted abandonment to their arrangements by including in the contract for service, an evergreen or roll-over provision. Thus, the Commission explained, in the first instance, the parties will decide whether the service obligations under the contract will be subject to pregranted abandonment.

Several LDCs, industrials, and state regulatory agencies[433] seek rehearing of the Final Rule because it fails to require pipelines to include a unilateral evergreen clause, giving the

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432. 18 CFR 284.221(d).

433. Industrial Groups; American Paper Institute; APGA; AGD; Cascade; New England Gas Distributors; Northern Illinois Gas; Northern Indiana; Northwest Natural; PSE&G; United Distribution Companies; Wisconsin Distributor Group; Citizen Action; State of Michigan.

customer the right to renew the agreement, in all long-term firm transportation contracts. These parties argue that customers, particularly small LDCs with one pipeline supplier, simply do not have the leverage to negotiate inclusion of roll-over clauses in their long-term contracts. The pipelines have market power over transportation, they argue, and have no incentive to give up the monopoly power they would have at the end of the contract. The Commission cannot rely on the availability of evergreen clauses as a justification of its pregranted abandonment proposal, they conclude, because unless such clauses are mandated, they will not in fact be a limit on the pipeline's monopoly power. In addition, Northern Illinois Gas is concerned that the pipelines could have discretion to include these clauses in contracts for incremental customers, but deny them to core customers.

Similarly, AGD asks the Commission to clarify that every firm transportation contract is deemed to carry with it an implicit mutual evergreen provision that the certificated firm transportation service will continue in the absence of notice by either party to discontinue the contract. Cascade asks the Commission to specify that a bilateral evergreen clause in a firm transportation contract of a primary term of one year or more is a contractual right to continue to receive service.

The Commission will not require pipelines to include unilateral evergreen clauses in all their long-term firm transportation contracts. Under current industry practice, evergreen clauses are frequently included in service contracts, and the Commission intended in the Final Rule to make clear that this device will remain available to parties who agree to this method of providing for continued service. However, a pipeline cannot offer evergreen provisions selectively. If it includes evergreen provisions in its contracts, it must do so on a

non-discriminatory basis.[434] Thus, the Commission finds that Northern Illinois Gas' concern is unfounded because pipelines do not have discretion to include evergreen clauses for certain customers and deny them to others.

The Commission will not find an implicit mutual evergreen clause in all firm transportation contracts and will not interpret such a clause, when included in a contract, as a right to continue service, as requested by Cascade. The Commission will not change the agreement of the parties in this way. The right of first refusal discussed below affords the protection necessary for customers that receive service under a contract that does not contain a roll-over clause.

3. The Right of First Refusal

As explained in the Final Rule, even if the parties do not include an evergreen or rollover clause in their contract, the existing customer is still assured of the right to continued service if it exercises its right of first refusal by matching competitive bids for the capacity. The effect and intent of this provision is to ensure against the inefficient or unnecessary retention of capacity at the expiration of the contract. To exercise the right of first refusal, the existing customer must agree to match the highest rate bid, up to the maximum just and reasonable cost-based rate, and the longest contract term offered by another shipper who wants the service.

a. Rate Requirement

Under the right of first refusal, in order to retain capacity, the existing customer must match the price offered by a

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434. Order No. 636 at p. 30,450 n.268.

competing bidder, up to the maximum just and reasonable cost-based rate. APGA argues that the protection afforded by capping the bidding at the maximum rate authorized by the Commission may be illusory because rates designed on the basis of SFV may be economically out of reach of many small LDCs, and the current contracts of many of these LDCs will expire after the four year mitigation period.

There is no basis for asserting that maximum rates approved by the Commission under the SFV method will be uneconomical for small LDCs. As discussed above, under the special rate provisions adopted by the Commission for small customers, small customers can continue to receive on a permanent basis unbundled transportation service under a one-part rate with an imputed load factor. Thus, rates of small LDCs eligible for this rate provision will be largely unaffected by SFV. Moreover, for customers paying rates based on SFV, Commission rate review will assure that the pipeline's rates are at a just and reasonable level; a just and reasonable rate by definition is not excessive. This argument rests on incorrect assumptions about SFV that are discussed more fully above. The cap on the bidding at the maximum just and reasonable level provides more than adequate protection that pipelines will not be able to charge monopoly rates for their service.

NASUCA asserts that, although the Commission maintains that the maximum rate will be just and reasonable, under an incentive proposal, the rate could increase without the Commission's approval and undermine the Commission's ability to assure just and reasonable rates. APGA also argues that incentive rates will compound the problem. NASUCA argues that the interplay of the right of first refusal and incentive regulation should be considered by the Commission on rehearing.

Appendix C

Under the proposed Incentive Regulation Policy Statement, the Commission would not approve an incentive rate mechanism that would result in unjust and unreasonable rates. Moreover, until the Commission finalizes that proposed policy or approves an incentive rate mechanism, these claims are highly speculative.

On the other hand, ANR Pipeline argues that the right of first refusal could result in allowing customers to renew service at a rate substantially below the maximum rate, resulting in a cost shift to other customers. ANR is concerned that another shipper could bid an unrealistically low rate, even though the existing customer would have been willing to retain service at its higher rate, and all the current shipper would have to do is beat the lower offer. Similarly, El Paso asks the Commission to clarify that the rule does not mean that a customer could retain service by matching a bid that was not accepted by the pipeline, and, thus, force the pipeline to discount.

If customers were able to renew service at less than the maximum rate, as suggested by El Paso and ANR, this would merely be reflective of the competitive market. If no one bids at the maximum rate, that would mean that the capacity is valued at less than the maximum rate. However, pipelines are not required to discount under the rule and are not required to accept any offer at less than the maximum rate. If a lower bid is not acceptable to the pipeline, there is, in effect, no bid to match and, under the terms of the rule, the shipper will receive continued service at a rate, between the minimum and the maximum, negotiated by the shipper and the pipeline.

b. Length of Contract Term

A number of LDCs and several industrials and state

agencies[435] argue that the Commission erred in adopting the requirement that the existing customer match the longest contract term bid. These parties argue that the requirement will create problems for LDCs and industrials, that there is no rational basis for imposing the requirement, and that it is discriminatory and violates section 7 of the NGA.

Generally, the LDCs seeking rehearing argue that the nature of the services they provide makes it impossible for them prudently to match longer contract terms bid by competitors. AGD asserts that there is a lack of mutuality of obligation between an LDC and its customers, *i.e.*, an LDC has a public service obligation to provide gas to its customers, but the customers have no obligation to buy gas from the LDC. Therefore, the LDC runs the risk of incurring substantial stranded costs if it is forced to match a long-term bid by a competing bidder. Illinois Power and New England Gas Distributors state that because of their public service obligation, LDCs will have no choice but to match the longest bid term for capacity needed to meet their obligations. Moreover, they continue, their decision to enter into a long-term contract can be challenged on prudence grounds at the state and local level. These parties argue that while certain cogenerators and producers can enter into contracts of several decades duration, an LDC's long-term needs will change over that period; an LDC cannot and should not have to match the term bid by cogenerators and producers in order to retain capacity to meet its public service obligations and serve its human needs customers.

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435. *E.g.*, American Paper Institute; Industrial Groups; Reynolds; AGD; APGA; Cascade; CNG LDCs; ConEd; Illinois Power; NYSE&G; New Jersey Natural; Northern Distributor Group; Northern Illinois Gas; Northern Indiana; Peoples Gas; PSE&G; United Distribution Companies; Pennsylvania PUC; and the State of Michigan.

United Distribution Companies also argue that this requirement tips the balance in favor of gas producers or marketers interested in obtaining a monopoly over certain customers. If a supplier is able to take firm capacity away from an LDC shipper with a public service obligation, United Distribution Companies argue, the LDC will have no choice but to buy gas from that supplier. United Distribution Companies assert that this would shift monopoly power away from the regulated pipelines to the unregulated suppliers.

Several industrials, American Paper Institute, Industrial Groups, and Reynolds Metals, also argue that not all gas users can commit to long-term contracts. American Paper Institute asserts that the length of time for which different gas users can commit to firm transportation service is often defined by the "life" of the commodity they produce or the process or assets they use in producing it.

The right of first refusal is intended to protect existing customers, and provide them with a right to continued service, while at the same time recognize the role of market forces in determining contract price and term. Bidding on the contract term, within the limits described below, as well as price, is appropriate and is a significant part of the right of first refusal. As explained in Order No. 636, one of the goals of the rule is to permit buyers and sellers to meet in a national market place and transact the most efficient deals possible.[436] When a contract has expired, it is most efficient, within regulatory constraints, for the capacity to go to the person who values it the most, as evidenced by its willingness to bid the highest price for the longest reasonable term. Generally, long-term contracts benefit the system as a whole because they provide stability and benefits to all customers.

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436. Order No. 636 at p. 30,393.

Appendix C

As explained below, LDCs are not at a disadvantage in this process because all parties have an opportunity to participate in the bidding process. Consistent with section 7 of the NGA, the existing customer has an advantage because it can always retain service by matching the highest bid.

Further, Industrial Groups argue that a customer who absolutely needs the service for two years may be forced to contract for ten years, in effect agreeing to pay far more than the regulated rate for the two years of needed service. Similarly, NYSE&G argues that long-term contracts in effect will require LDCs to pay higher than authorized rates when consideration is given to the added cost of engaging capacity longer than is needed.

No customer will ever pay a rate higher than the maximum just and reasonable rate for service, regardless of the duration of the contract. Those who value the service most should receive the capacity. If one party values the service for two years, but another potential customer values it more and bids ten years, the capacity should go to the highest bidder.

The capacity release mechanism established in the Final Rule will not solve these problems, APGA, NYSE&G, New Jersey Natural, and Northern Illinois Gas argue. NYSE&G maintains that while capacity assignment may provide some relief, it is not clear that assignees will always be available. Further, Northern Illinois Gas argues that if the LDC wants to shed the capacity in order to take advantage of more attractive rates, those rates will also attract the parties to whom the capacity might otherwise be assigned.

The capacity release program does provide a meaningful

opportunity for an existing customer to release unused capacity. It does not guarantee that all unused capacity will be sold, but it does give the customer an important means of realigning capacity to meet its needs. If a customer values the service highly enough to bid the longest term, but subsequently does not need all the capacity and is not able to find a substitute shipper, there is no reason to relieve the highest bidder of its decision to contract and shift the risk of loss to the pipeline and its other customers. The result under the rule is consistent with normal commercial practices.

Several other parties, including the State of Michigan, Illinois Power, Northern Distributor Group, United Distribution Companies, and the Wisconsin Distributor Group argue that the effect of this requirement, *i.e.*, tying up capacity for long periods of time, is actually contrary to the goals of Order No. 636. Illinois Power maintains that if an LDC is required to sign up for service for longer than is necessary, it will be unable to obtain competitive transportation or storage from a new or alternate pipeline. Similarly, Northern Illinois Gas argues that the requirement will force pipelines into long-term contracts, resulting in the inflexibility that caused the problems of the 1980's and possibly reducing the demand for natural gas. Many of the parties objecting to this requirement argue that a balance could be struck between the pipeline's need for stability and the customer's need for flexibility by placing a reasonable cap on the contract term which the existing customer must bid. AGD, Industrial Groups, ConEd, NYSE&G, New Jersey Natural, PSE&G and Wisconsin Distributor Group argue that an existing customer should be able to retain service if it meets the maximum rate bid for a term of five years. Reynolds argues that the cap should be at three years, and United Distribution Companies support a cap at between three and five years.

Northern Distributor Group believes that, consistent with the definition of long-term transportation, the term should be one year. Cascade argues that the term should be limited to 10 years, consistent with the finding in Order No. 555 that 10 years is sufficient to prove valid markets. State of Michigan also believes that 10 years is an appropriate cap.

The right of first refusal should not result in tying up capacity. Instead, it will permit the market to determine the appropriate contractual length. However, upon consideration of the parties' arguments, the Commission finds that capping the contract term that must be matched by a customer exercising its right of first refusal at a period of 20 years strikes an appropriate balance between the pipeline's need for stability, the customer's need for flexibility, and the Commission's overall goal in Order No. 636 to foster long-term, market driven arrangements in the gas industry. This cap, in the Commission's judgement, ensures that the customer obtaining the service values the service sufficiently to commit to using it for a reasonable period and provides the pipeline with a reasonable level of stability. Twenty years has been the traditional length of long-term contracts in the natural gas industry and a number of recent contracts for new capacity are for a twenty year term.[437]

c. Legal Basis

Some parties object to the right of first refusal on legal as well as practical grounds, arguing that the procedure violates section 7 of the NGA and is contrary to court decisions interpreting that section. APGA argues that the Commission

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437. *See, e.g.*, Pacific Gas Transmission Co., 56 FERC ¶ 61,192 (1991); Iroquois Gas Transmission System, L.P., 53 FERC ¶ 61,194 (1990); *reh'g granted in part and denied in part*, 54 FERC ¶ 61,103 (1991).

violates *American Gas Association v. FERC (AGA II)*[438] by not addressing the LDCs' concerns that they will have to yield to the pipeline's monopolistic demands to receive service. Further, APGA argues, the Commission erred in stating that the service obligation should first be determined by contract because this ignores legal precedent holding that a pipeline has a service obligation regardless of the contract.[439] APGA concludes that in order to comply with the requirement of section 7, the Commission must give the LDCs some reasonable protections and not make them subject to the superior buying power of others.

The right of first refusal procedure does provide protection to the existing customer and guarantees that the LDCs will not have to yield to the pipeline's monopoly power. Further, the Commission has not ignored legal precedent regarding the pipeline service obligation. Under the right of first refusal procedure, the existing customer can always retain service, but not necessarily at a discount, and not necessarily on a short-term basis, if other potential customers value the service and are willing to pay the maximum just and reasonable rate for a longer term. If there are no other bidders, the pipeline's transportation service obligation continues, and the parties negotiate a new contract. If there are other bidders, the existing customer retains service by matching the price, up to the maximum just and reasonable rate, and the longest bid contractual term. These are not monopolistic demands. They

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438. 912 F.2d 1496 (D.C. Cir. 1990); *cert. denied*, 111 S. Ct. 957 (1991).

439. APGA cites Sunray Mid-Continent Oil Co. v. FPC, 239 F.2d 97, 101 (10th Cir. 1956), *rev'd and remanded on other grounds*, 353 U.S. 944 (1957); Farmland Industries, Inc. v. Kansas-Nebraska Natural Gas Co., 486 F.2d 315 (8th Cir. 1973); and Sunray Mid-Continent Oil Co. v. FPC, 267 F.2d 471 (10th Cir. 1959), *aff'd*, 364 U.S. 137 (1960).

are contractual terms which reflect conditions in the market place. The highest rate the existing customer must match is the maximum just and reasonable cost-based rate, which by definition cannot be a monopoly rate. Nor is the longest bid contractual term a monopolistic demand, but is merely a term other competing customers will bid for the service.

Atlanta Gas also argues that the right of first refusal violates section 7 of the NGA. It asserts that the NGA requires that the Commission make a finding that the present or future public convenience and necessity permit the abandonment, and that this standard does not permit a pipeline to discontinue service to a customer simply because it cannot match an offer made by another would-be customer. Atlanta Gas argues that *Mobil Exploration and Producing Southeast, Inc. v. United Distribution Companies*[440] is distinguishable from this case because there pipeline purchasers were protected by the ability to obtain gas elsewhere, while here the Commission has not determined that the parties loosing transportation capacity will be able to obtain capacity elsewhere.

Similarly, New England Gas Distributors argue that the procedure violates the court's mandate in *AGA II*[441] because the Commission does not explain how pregranted abandonment trumps protection of consumers against the exercise of monopoly power through refusal of service at the end of the contract term. To justify the procedure, New England Gas Distributors argue, the Commission must explain why the right of first refusal protects consumers and meets the Commission's statutory obligations; they contend that this is impossible because the

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440. 111 S. Ct. 615 (1991).

441. 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991).

notion of LDCs meeting better offers to retain service is inconsistent with section 7 and ignores that LDCs are public utilities with a public service obligation. Similarly, United Distribution Companies argue that the court in *AGA II* emphasized that the overriding purpose of section 7(b) is to protect consumers from monopoly power and unjustified termination of service.

PSE&G also argues that the Commission has misinterpreted the court decisions interpreting section 7(b). Both *AGA II* and *Mobil Exploration*, they argue, require a finding that the public convenience and necessity permits abandonment, and the Commission has failed to show how customers will be protected from monopoly abuses.

In Order No. 636, the Commission made a generic finding that the public convenience and necessity permits abandonment where the existing customer does not value the service sufficiently to match a competing bid. The right of first refusal will protect customers because it permits the existing customer to retain service. The pipeline is not able to refuse transportation service at the end of the contract term or to make monopolistic demands as a condition for continued service. The pipeline must continue to provide service to the existing customer if there are no competing bids for the service, and if the existing customer matches a competing bid for service, the pipeline must continue transportation service pursuant to those terms.

American Paper Institute argues that the requirement that the existing customer match the longest contractual term bid is discriminatory and violates section 7 of the NGA because the length of time to which a customer can commit is not related to public benefits of the various industries or most efficient use of capacity. American Paper Institute states that the Commission

itself has recognized that there should be no discrimination based on duration of service.[442] Similarly, APGA argues that it is error to equate those with the greatest need for service with those who can offer the longest contract term. CNG LDCs also argue that the requirement is discriminatory and distorts the bidding process by reflecting status and bargaining position rather than market forces.

The requirement is not unduly discriminatory. All parties have an equal opportunity to bid for the capacity and, consistent with section 7, if the existing customer matches the bid for the longest term, it retains the capacity. While the LDCs argue that they should have priority because they serve human needs, other customers serve human needs as well. Moreover, the most efficient use of capacity is for it to be used by the party who values it the most. The bidding requirement is intended to help allocate transportation capacity to that party.

United Distribution Companies argue that an LDC should have an express right to a hearing under section 7(b) if it certifies that the capacity is needed to serve core customers. United Distribution Companies assert that including this provision would make Order No. 636 analogous to Order No. 451, which provided that any customer faced with an unjustified loss of gas under the Order's procedures was entitled to a complaint proceeding.

The Commission's complaint procedure is always available to remedy an unjustified loss of service. A hearing is necessary, however, only if there are material facts in dispute. As the

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442. American Paper Institute cites 18 CFR 284.8(b), 284.9(b); Arkla Energy Resources, 48 FERC ¶ 61,305 at 61,985 (1989); Arkla Energy Resources, 47 FERC ¶ 61,045 at 61,131 (1989).

Commission has explained, the right of first refusal is an adequate protection for LDCs serving core customers.

d. Mechanics

Several parties ask the Commission to clarify or amend the mechanics of the right of first refusal process. ConEd asks the Commission to clarify that a long-term firm transportation customer has the right to extend service at the maximum rate for a period of more than one year where the contract expires, the pipeline gives notice of its intent to terminate, there are no competing bidders for the capacity, and the parties cannot agree to new terms. Otherwise, ConEd asserts, the pipeline could force the customer to accept a short-term contract or an unreasonably long-term contract. AGD also asks the Commission to clarify that where there are no competing bids, the firm transportation holder has a right to extend its contract for a period of more than one year, in order to protect it against pregranted abandonment.

The Commission clarifies that, when there are no competing bidders for the capacity, and the existing shipper agrees to pay the maximum rate, the existing customer is entitled to continue the transportation service for whatever term it chooses.[443] The pipeline may not withhold service at the maximum rate.[444] If there are no competing bids, the existing holder has in effect tendered the "longest" term offered for that capacity.

Elizabethtown asks for clarification of section

443. Of course, the pipeline could agree to less than the maximum rate in such circumstances.

444. Order No. 636 at p. 30,449.

284.221(d)(2)(ii) of the regulations which provides that pregranted abandonment does not apply if the individual transportation arrangement is for firm transportation under a contract with a term of more than one year, and the firm shipper:

> Gives notice that it wants to continue its transportation arrangement and will match the longest term and highest rate for its firm service, up to the maximum rate under § 284.7, offered to the pipeline during the period established in the pipeline's tariff for receiving such offers by any other person desiring firm capacity, *and* executes a contract matching those terms.

Elizabethtown is concerned that the use of the conjunctive in the last clause could be interpreted to mean that the shipper would experience pregranted abandonment if no one submitted a bid for the firm capacity and, therefore, no opportunity was available to the shipper to execute a contract matching an alternate bidder's terms. To avoid confusion, Elizabethtown suggests that the last clause be amended to read as follows:

> and, if such offer was made to the pipeline, executes a contract matching those terms.

To avoid confusion, the Commission will revise the regulation to avoid the construction pointed out by Elizabethtown.

Tennessee and Columbia Small Customers ask the Commission to clarify that only customers in the same rate class will bid against each other and that customers formerly receiving service under rate schedules GS and SGS need not match bids by larger customers for the same capacity. Tennessee and

Columbia Small Customers reason that because the Final Rule provides that "the maximum rate that must be matched is the highest rate the pipeline is authorized to charge for the capacity sought,"[445] if the "capacity sought" is firm transportation service that had been converted from former GS or SGS service, larger customers would not be eligible to bid. Further Tennessee and Columbia Small Customers argue, to permit large customers to bid against small customers would be grossly in equitable and inconsistent with the mitigation measures that the rule required.

Tennessee and Columbia Small Customers have misinterpreted the rule. The rule is not intended to limit the parties who may bid on capacity to those in a single rate class. However, Tennessee and Columbia Small Customers are not disadvantaged under the pregranted abandonment rule in section 284.221(d) because customers must only bid up to the maximum just and reasonable rate the pipeline can charge to them, not the highest rate the pipeline can charge for the capacity.[446]

United Distribution Companies argue that the pipeline should not have the discretion to determine what constitutes the best offer. Procedures for implementing the right of first refusal, including an appropriate method of determining the best offer must be developed in the individual restructuring proceedings, in which LDCs will be able to participate in developing the standard to be used by each pipeline.[447] However, any standard must be an objective one, based on economic factors. The Commission's intent is to permit variations by pipelines but to ensure that whatever objective standard a pipeline chooses would

445. Order No. 636 at p. 30,449.

446. *Id.*

447. Order No. 636 at p. 30,451.

be put in its tariff so that all parties would know the rules in advance.

e. Bona Fide Offers

Industrial Groups argue that the Commission should adopt procedures similar to those adopted in Order No. 451 to assure that bids are *bona fide*, *i.e.*, that bids be in writing, accepted in principle, and achieved in arm's length transactions. Northwest Natural argues that the regulations should preclude the pipeline and affiliates from submitting offers and should provide that a shipper should only have to match an offer from a non-affiliate. Northwest Natural states that this is required by the policy underlying the affiliated entities rule in the NGPA and that pipelines and affiliates should not be allowed to repackage services into anticompetitive packages.[448] Northwest Natural further argues that the Commission's rationale for not imposing the requirement is inadequate because the parties cannot in fact protect themselves through contractual provisions. The Pennsylvania PUC and New Jersey Natural argue that the matter should not be left to the restructuring proceedings without any direction from the Commission. Rather, they assert, the Commission should establish guidelines and controls.

Pipelines should adopt procedures similar to those adopted in Order No. 451 to assure that offers are *bona fide*. Additionally, with regard to potential affiliate abuses, and the policy underlying the affiliaties entities rule in the NGPA,[449] as raised by Northwest Natural, the Commission notes that Order No.

448. Northwest Natural cites NGPA § 601(b)(1)(E), 15 U.S.C. § 3431(b)(1)(E).

449. *See, generally*, Order No. 269, Tennessee Gas Pipeline Co., 38 FERC ¶ 61,306 (1987).

497 addresses, at least in part, the concerns expressed by the Pennsylvania PUC and New Jersey Natural, and Northwest Natural.[450] Further, it may be appropriate for the Commission to scrutinize carefully transactions where the only competing bidder is an affiliate. However, the Commission is not able to provide specific criteria at this time, and thus, defers this issue for further consideration if a particular concern is raised in the restructuring proceedings.

f. Offers for a Portion of Existing Customer's Capacity

AGD asks the Commission to clarify that the holder of firm transportation service may retain any portion of its certificated service that it wishes to retain, subject to the rules governing the right of first refusal, and have the pipeline's pregranted abandonment authority apply to the remainder of the capacity. AGD states that the final rule makes clear that a prospective shipper may bid against a current firm transportation capacity holder with respect to a portion of the capacity held by the existing holder, but does not address what should be the concomitant right of the firm service holder to bid for the right to retain some amount less than the full amount of the capacity subject to pregranted abandonment.

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450. For example, the standards of conduct (18 CFR 161.3) state, *inter alia*, that a pipeline may not, through a tariff provision or otherwise give its marketing affiliate preference over nonaffiliated customers in matters relating to Part 284 transportation including, but not limited to, scheduling, balancing, transportation, storage, or curtailment priority (standard (c)); may not disclose to its affiliate any information the pipeline receives from a nonaffiliated shipper or potential nonaffiliated shipper (standard (e)); and, to the extent it provides to its marketing affiliate information related to transportation of natural gas it must provide that information contemporaneously to all potential shippers, affiliated and nonaffiliated, on its system (standard (f)).

Appendix C

The request for clarification is granted. The rule is intended to permit the existing capacity holder to elect to retain a portion of its capacity subject to the right of first refusal, and permit the pipeline's pregranted abandonment to apply to the remainder of the service.

The Wisconsin Distributor Group, on the other hand, objects to the provisions that a competing bidder may bid for a portion of the capacity. The Wisconsin Distributor Group states that sellers often offer more favorable rates to purchasers of large quantities for long hauls because of the increased efficiencies associated with these transactions, and that Order No. 636 eliminates the benefits of their economies of scale for large purchasers. The Wisconsin Distributor Group argues that competing bids should be for the same capacity that the existing customer seeks to retain, *i.e.*, the same quantity and the same route. The request for rehearing is denied. As explained in Order No. 636, the policy urged here by the Wisconsin Distributor Group would virtually insulate the very largest holders of capacity from the bidding process.

Natural argues that the Commission erred insofar as the rule provides that the existing shipper need only match a bid for its existing transportation path. Under the rule, Natural argues, an existing shipper could preclude a system haul by creating a bottleneck on the system. Natural states that a short haul should not be allowed to preclude a long haul unless the short haul shipper is paying the same total rate as the long haul. Natural argues that the final rule is an unlawful taking in that it prevents a pipeline from obtaining greater revenue associated with long hauls.

The request for rehearing is denied. The Commission has

answered the Constitutional arguments against this rule. Section 7 of the NGA provides protection against abandonment for current customers that are not in the public interest, and Order No. 636 merely amends Commission procedure for implementing that protection. The policy advocated by Natural would virtually guarantee that the long-haul shipper could take capacity from the current shipper if the current shipper transported the gas for a shorter distance. Natural has confused the bidding process for released capacity under section 284.243 of the regulations with the right of first refusal which is designed to give the existing customer the right to continued service. Under the capacity releasing mechanism, where two new customers are bidding for the same capacity, the regulations require the pipeline to allocate released capacity to the person offering the highest rate no over the maximum tariff rate the pipeline can charge to the releasing shipper. This means that the person seeking to obtain the released capacity can offer up to the pipeline's filed maximum rate for the service received by the releasing shipper, even if the replacement shipper wants the capacity to move gas for a shorter haul.[451] However, under the pregranted abandonment provision, the existing shipper must bid only the maximum rate the pipeline is authorized to charge that shipper.

United Distribution Companies also objects to this provision, arguing that it would permit competitors to fragment the LDCs' needed capacity. As explained above, the procedure guarantees the LDC the right to continued service if it matches the bid of a competing bidder. The capacity will not be fragmented if the LDC exercises its right of first refusal.

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451. Order No. 636 at 30,420-421.

Appendix C

g. Converted Sales

Northwest Natural argues that all converted firm sales service should be protected from pregranted abandonment, including transportation converted outside the stay period. Northwest Natural argues that the rule discriminates against LDCs that converted outside the stay period, and is inconsistent with the decision in *American Gas Association v. FERC.*[452] Northwest Natural argues that the proper result is to treat all converted firm transportation the same, and provide that it will never be subject to pregranted abandonment. United Distribution Companies also argue that the exemption for Order No. 500-J conversions is discriminatory and that the exemption should be expanded to include all existing contracts for long-term transportation service in which the pipeline waived its right to pregranted abandonment. United Distribution Companies assert that where LDCs negotiated for protection against pregranted abandonment, they should be able to retain the benefits of their bargain, and pipelines should be held to their bargains.

The exemption for conversions that took place during the Order No. 500-J stay is based on our decision in Order No. 500-J and the expectations of the parties based on that decision. There is no reason to expand the exemption. The effect of specific contractual provisions or specific contracts that contain a waiver of the right to pregranted abandonment should be examined in the restructuring proceedings, not in this generic proceeding.

Cascade asserts that it is unclear whether Northwest's just approved conversions in Docket No. CP92-79-000 meet the requirements of section 284.221(d)(3). Cascade states that while these conversions were approved May 1, 1992, during the stay

452. 912 F.2d 1496 (D.C. Cir. 1990).

period, they have not yet been completed because their implementation has been tied to actions in other applications. Cascade asks the Commission to clarify that these now approved conversions fall within the section 284.221(d)(3) exemption, or, grant a waiver of the rule for these conversions.

The Order No. 500-J stay applies only to conversions that took place during the period the stay was in effect. The conversions approved in the Northwest proceeding have not yet been implemented and, therefore, the stay does not apply. There is no reason to waive the rule's requirements, and the regulations governing pregranted abandonment will apply to this transportation service on Northwest.

h. Special Circumstances

Kern River argues that the right of first refusal should not apply to any of its customers because at the time those customers executed their service contracts, the Commission's regulations provided for pregranted abandonment. Therefore, Kern River argues, its customers never expected individual abandonment proceedings and know that their service would cease upon contract expiration.

The Commission will not exempt Kern River from the regulations governing the right of first refusal. Kern River should raise this issue in its restructuring proceeding.

4. Storage

AGD and ConEd ask the Commission to clarify that the rules governing pregranted abandonment apply to open access storage arrangements. The rule promulgated by Order No. 636

defines transportation to include storage. Therefore the rules applicable to transportation apply to storage provided under Part 284 as well.

IX. TRANSITION AND IMPLEMENTATION IN THE RESTRUCTURING PROCEEDINGS

A. Adjustment of Purchase Obligations and Firm Capacity

Under section 284.214(d), as promulgated in Order No. 636, firm sales customers may reduce or terminate their rights or obligations to purchase gas by giving notice to the pipeline during the restructuring proceeding.[453] The pipeline is authorized to abandon the sale of gas to the firm customer to the extent the customer exercises such right, or declines to pay the pipeline's restructured sales rate.

Under section 284.214(e), firm shippers must give notice to the pipeline during the restructuring proceeding of whether they want to retain, reduce, or terminate their contractual rights to firm transportation service, and the pipeline must permit reduction or termination of those rights if another shipper bids for the capacity, or may agree to the reduction or termination of such rights in any event. The pipeline is authorized to abandon

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453. Northern Indiana states that it does not understand the Commission's use of the phrase "purchase obligations" in describing LDCs' sales contracts with pipelines, since Order No. 380 and subsequent Commission decisions have eliminated "purchase obligations" under such contracts. Northern Indiana's point is well taken. In the absence of minimum bill provisions, sales customers have rights or entitlements to purchase gas, and obligations to pay demand charges, but no obligations to purchase gas.

service to shippers accordingly. If another shipper is prepared to bid more than the current capacity holder pays for its capacity, the current capacity holder must be willing to match what the competing bidder offers, up to the maximum rate, or release the capacity.

1. Unconditional right to cost-free release of capacity

Pacific Gas and Electric Company (PG&E) asserts that the service and rate changes contemplated by Order No. 636 will almost certainly make some existing transportation contracts far more desirable, while making others wholly unnecessary or far less desirable. PG&E points out that in the Rate Design Policy Statement, the Commission directed parties to address and explore various ways to provide a contract demand adjustment in tandem with increased charges for peak service.[454] However, PG&E argues that the Commission's decision in Order No. 636 to require firm capacity holders to bid to retain constrained capacity, while not providing for unilateral contract reduction rights for unneeded or undesirable capacity, is inequitable and inconsistent with reasoned decision-making.

APGA recognizes that an unrestrained release mechanism during restructuring could cause chaos, but urges the Commission to afford all existing firm capacity holders a unilateral right to turn back some excess capacity during the restructuring proceedings, a maximum of 10,000 MMBtu per day or a modest percentage of current CD, whichever is greater. Customers should be permitted to adjust their demand in response to changes in price that will result from implementing SFV. According to APGA, many small customers have contract

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454. 47 FERC ¶ 61,295 at p. 62,055 (1989).

entitlements in their service agreements that are in excess of their actual current peak day requirements because there are no direct cost consequences of maintaining such levels of entitlements under current rate designs. APGA argues that small customers currently served under a one-part bundled sales rate, under full requirements service, or under two-part schedules with ratcheted demand charges based upon peak deliveries rather than contract entitlements should be authorized to elect an amount of firm transportation capacity during restructuring up to their former contact demand for sales service. APGA argues that pipelines should be at risk to remarket turned-back excess capacity, rather than requiring firm capacity holders to keep and pay for capacity they do not require and for which no other buyer can be found.

As a general matter, pipelines are entitled to recover their legitimate capacity costs, and have designed their rates to do so on the basis of CD levels under their existing firm service contracts. If capacity entitlements are reduced by certain customers and not picked up by others, pipelines will underrecover their capacity costs unless they recover an exit fee from the releasing customer, or until they increase their demand charges under a Section 4 rate filing to reflect the net loss of capacity demand. When they increase their demand charges, capacity costs will be shifted to other firm customers that have not reduced their CD levels. Therefore, the Commission cannot give pipelines' firm customers a unilateral right to reduce or terminate their capacity entitlements during the restructuring proceedings, unless another customer contracts for the released capacity and assumes liability for the costs of the capacity, without shifting costs to the pipeline or other firm customers, or both. No reason has been presented why, during the term of the currently effective contract, these capacity costs should be shifted from the customer who has contracted for the

capacity to the pipeline or other customers that have no need for the capacity.[455]

On the other hand, the Commission in Order No. 636 *requires* all firm customers to evaluate their capacity needs and notify the pipeline during the restructuring proceedings whether they want to retain, reduce, or terminate their current levels of capacity reservation. Furthermore, pipelines are required to permit their firm customers to permanently reassign their capacity to other parties that are willing to pay for it at the restructured rate. Thus, LDCs are afforded unilateral contract reduction rights for unneeded capacity, if they are small customers, or if there are replacement shippers, contrary to PG&E's assertion that they are not. Furthermore, the pipeline and LDC may negotiate a bilateral reduction in capacity even if there is no demand for the capacity from other shippers. But the direction in the Rate Design Policy Statement, and in this proceeding, that parties consider mechanisms for implementing capacity adjustments, does not relieve firm capacity holders from liability for the costs of their capacity reservations under their currently effective contracts (unless the pipeline agrees to such relief) where there is no demand for the capacity by other potential shippers.

Northern Indiana argues that the Commission exceeded its power by mandating that sales customers retain excess transportation capacity. According to Northern Indiana, the Commission in Order No. 636 has abrogated the LDCs' bundled sales contracts, and has no jurisdiction to require LDCs to retain and pay for any minimum quantity of transportation capacity

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455. Pipelines may, however, permit their customers to adjust their contract demands on a seasonal basis as a means of avoiding cost shifts from the implementation of the SFV rate design.

under a service arrangement that is grounded in an abrogated contract. Northern Indiana argues that even if the Commission had the power to rewrite LDC contracts and bind them to something they did not sign, LDCs must have the right to contract and pay for only the transmission capacity they want on each of their pipeline suppliers for there to be any real restructuring and true competition. Furthermore, Northern Indiana argues, customers should not remain bound for years to pay demand charges associated with contracts negotiated prior to the open access era.

The Commission has not abrogated LDCs' bundled sales contracts, contrary to Northern Indiana's assertion. The Commission has required pipelines to provide the sales and transportation under such contracts pursuant to separate certificates of public convenience and necessity, and has required that the point of sale be moved upstream from the city gate. The Commission exercised its authority under Section 5 of the NGA, and its power to fashion remedies, to permit LDCs to reduce or terminate their sales entitlements under existing sales contracts. However, the fact that LDCs have an opportunity to revise their sales entitlements under existing contracts with their pipeline suppliers does not mean they should also have an unqualified right to reduce or terminate their obligations for the costs of transportation capacity under those contracts.

The CPUC seeks clarification that a firm capacity holder may permanently relinquish a portion of its capacity rights without paying an exit fee, if there is demand for the capacity rights, even if the new shipper is not willing to pay the maximum rate for the capacity. CPUC argues that since the original firm capacity holder might not have been willing to pay the pipeline's maximum rates under an SFV rate design, the Commission

should not burden that holder with the full costs of an SFV rate design (*i.e.* through exit fees) simply because others interested in the capacity rights are also unwilling to pay the maximum rates. According to CPUC, a bid at less than the maximum rate reflects what the market is willing to pay for the capacity rights, and permitting a cost-free relinquishment to the bidder who is willing to pay for the capacity would promote the goal of allocative efficiency.[456] Cincinnati Gas argues that existing capacity holders should be permitted to offer a lower rate than the maximum to retain their capacity, even if there are no competing bidders, and to release the capacity cost-free if the pipeline is unwilling to accept the lower rate.

The Commission rejects CPUC's request in order to avoid stranded costs that would have to be absorbed by the pipeline or other customers. However, a pipeline must release an existing capacity holder from its contractual obligations for the capacity if a competing bidder makes an offer for capacity held by the existing firm customer that is equal to or greater than the rate the existing customer is obligated to pay, up to the maximum rate. Of course, the existing capacity holder may offer to pay an exit fee to the pipeline as inducement to release it from those contractual obligations, but that is a matter for negotiation between the parties. Section 284.14(e) provides for automatic abandonment during restructuring when a pipeline agrees to release the existing capacity holder from its contractual obligations, without regard to what inducements are made to the pipeline to secure such agreement. CPUC may be correct

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456. Memphis Light also argues that, during restructuring, LDCs should be able to bid on the capacity they already hold at less than the maximum rate, and if they are the highest bidder, or if there are no other bidders, be entitled to receive service at the rate they bid, even if the pipeline does not agree to a discount.

that a bid for the capacity at less than the maximum rate reflects current market conditions. But the Commission is not implementing non-cost-based pricing for pipelines' transportation capacity in this proceeding. If CPUC's or Cincinnati Gas's proposed clarifications were adopted, a portion of the costs of the capacity in question would be shifted from the customer that contracted for the capacity to the pipeline or other customers that have no need for it.

Transco also seeks clarification of the same point, but to the opposite effect, namely that an existing holder of firm capacity is not fully relieved of its contractual obligations unless a third party bidder agrees to pay the maximum rate for the capacity to be relinquished. Clarification along these lines, Transco argues, would be consistent with the policy under the temporary capacity release program of the new section 284.243, where the original capacity holder remains liable for the applicable rate for released capacity, even though the replacement shipper pays a lesser rate. El Paso seeks clarification that an existing shipper may not release, and be released from liability for, *all* of its capacity under its current contract when there is a bid for only a *portion* of it.

Except to the extent pipelines are "at risk" for unsubscribed firm capacity, they are entitled to seek to recover their capacity costs through a fully allocated cost-based rate. However, a pipeline may have contracted to provide firm service for less than the maximum rate. For the reasons discussed above, a pipeline would underrecover its capacity costs if existing firm capacity holders were fully relieved of their liability under currently effective capacity reservations where a replacement shipper agrees to purchase that capacity at less than the rate the current shipper is obligated to pay. If another creditworthy shipper offers to pay a rate that is equal to or greater than the

existing capacity holder's rate, up to the maximum rate, for a part of the capacity that an existing capacity holder seeks to release, the pipeline must release the existing capacity holder from its contractual obligations for the capacity sought by the other. But the pipeline is not required to release the existing capacity holder from liability for capacity for which another bidder offers less than the rate the existing capacity holder is obligated to pay. The pipeline is no worse off when the substitute shipper pays the same rate the releasing shipper is paying, even though that rate is less than the maximum rate.

2. Pipeline opportunity to adjust contracts for capacity

ANR requests the Commission to clarify that not only shippers, but also pipelines, have opportunities to adjust certain contractual commitments during restructuring. ANR asserts that a contract for firm capacity at a substantial discount, entered into when capacity release rights were not available, could become substantially more valuable after implementation of Order No. 636. Unless it is allowed to make adjustments to the contract, ANR asserts that the current shipper may release the discounted transportation to another shipper in different competitive circumstances that might not warrant the discount.

Even if an existing capacity holder's contract for transportation at a discount becomes more valuable because of the capacity release program, the pipeline's ability to increase the rates for the service will depend on whether its contract affords it a right to renegotiate or eliminate the discount. If there is demand for the capacity at higher rates, and the existing capacity holder's discount is not contractually guaranteed, the existing capacity holder will have to match the competing bids, up to the maximum rate, or release the capacity.

3. Reduction or termination of transportation capacity embedded in bundled sales service

SoCal Edison requests the Commission to clarify that the CD levels of transportation capacity embedded in a bundled sales service can only be reduced or terminated during restructuring under the same conditions that capacity may be released by existing transportation customers. SoCal Edison is correct, and the clarification is accordingly granted. Under Order No. 636, the capacity rights of bundled sales customers are converted into unbundled firm transportation rights. At that point, the sales customers are to be treated no differently from other firm transportation customers.

4. Right of first refusal during restructuring proceedings

Citizens Gas apparently interprets Order No. 636 to provide that existing firm capacity holders are subject to losing their capacity during the restructuring proceedings unless they exercise a "right of first refusal" by agreeing to match any greater rate up to the maximum rate, and the most favorable contract term offered by any other person seeking the capacity.[457] Citizens Gas seeks rehearing of this provision on various grounds. Citizens Gas is mistaken about what Order No. 636 provides. An existing firm capacity holder may have to match a competing rate bid for its capacity during restructuring if it is receiving transportation at a discount, and does not have a contract that guarantees it that discount, but it does not have to match any other term of competing offers to retain its capacity. The final rule differs from the proposal in the NOPR in this respect. Furthermore, the requirements for retaining firm capacity under

457. Cincinnati Gas seeks clarification of this same issue.

currently effective contracts during restructuring proceedings are different from those for retaining firm capacity, *i.e.* by exercising a right of first refusal, when a contract has expired.

5. Permitting immediate reduction or termination of customers' sales entitlements

Marathon seeks rehearing of the Commission's decision in Order No. 636 to permit immediate reduction or termination of pipeline customers' sales entitlements, arguing that it will create significant dislocation and confusion in the natural gas industry. Marathon submits that economic dislocation and the transition costs involved in restructuring long-term supply agreements could be minimized by allowing existing pipeline gas sales contracts to run their course, and suggests the Decontrol Act as a model for an orderly transition. Under that Act, deregulation is phased in as contracts expire or are terminated, and parties may expressly agree to deregulated prices in continuing contracts.

The Commission indicated in Order No. 636 that sales customers may choose not to exercise their right to reduce or terminate their sales entitlements during restructuring to its fullest extent, in order to avoid or minimize transition costs. The Commission's decision allows sales customers the choice of whether to continue their sales contracts with their pipeline suppliers or arrange for other suppliers and bear the consequences of making that choice. At the same time, pipelines are permitted to sell their gas at market-sensitive prices, thus enabling them to offer more competitive rates to retain their sales customers. Marathon is the only party that raises this issue on rehearing. The industry as a whole seems to accept the Commission's judgment that affording pipeline sales customers a right to reduce or terminate their sales entitlements during

restructuring is an appropriate remedy for their previous inability to secure reliable service any other way because of the lack of high quality firm transportation. Marathon's request for rehearing on this issue is denied.

6. Revisions to 18 C.F.R. § 284.14(e)

Section 284.14(e)(4) provides that a downstream pipeline may not terminate its capacity rights on an upstream pipeline during restructuring proceedings. National Fuel requests that a downstream pipeline be permitted to pursue capacity reductions on upstream pipelines during the restructuring proceedings if it first gives notice to its historical sales customers and receives no objections that it cannot resolve. According to National Fuel, the lack of opportunity to reduce unneeded capacity will disadvantage downstream pipelines and their customers, where neither has any need for excess capacity on the upstream pipeline. National Fuel also seeks clarification that the prohibition against downstream pipelines releasing upstream capacity during restructuring does not preclude downstream pipelines from converting from sales to transportation on the upstream pipeline during restructuring proceedings.

The Commission will grant National Fuel's request and revise the regulatory text accordingly, to permit a downstream pipeline to pursue capacity reductions on upstream pipelines with the consent of the potentially affected customers of the downstream pipeline. As discussed above, the downstream pipeline's ability to reduce its capacity on upstream pipelines will depend on the willingness of other parties to contract for the upstream capacity or the willingness of the upstream pipeline to agree to a reduction in the absence of another buyer.

Appendix C

The Commission is also revising certain other provisions of section 284.14(e), to conform it to the provisions of the preamble of Order No. 636. Specifically, paragraph (e)(2) is revised to provide firm shippers an explicit right to reduce or terminate their firm service rights and obligations where the pipeline receives an offer for the capacity during the restructuring proceeding from a creditworthy shipper that is equal to or greater than the rate the existing shipper is obligated to pay, up to the maximum rate, or the pipeline otherwise agrees to a reduction or termination. Furthermore, paragraph (e)(3) is revised to permit the pipeline to abandon service to a firm shipper if, during the restructuring proceeding, another shipper offers a higher rate, up to the maximum rate, which the existing shipper (who is not contractually entitled to a discount) declines to match.

B. Transition Costs and Recovery Mechanisms

The Commission recognized in Order No. 636 that pipelines may incur certain transition costs as a direct result of implementing the requirements of that order. The order envisioned four kinds of such costs: unrecovered gas costs in a pipeline's Account No. 191, to be recovered by means of a "direct bill" to its former, bundled firm sales customers; gas supply realignment (GSR) costs that result from a pipeline having to reform or terminate existing supply contracts in response to customer decisions during the restructuring proceedings, to be recovered from Part 284 firm transportation customers by means of a reservation fee surcharge or a negotiated exit fee; costs that are now incurred in connection with bundled sales service that cannot be directly assigned to customers of unbundled services, called "stranded costs," to be included for recovery in a general rate case under section 4 of the NGA; and the costs of new facilities to physically implement

Order No. 636, also to be included for recovery in a general rate case.

About 70 of the requests for rehearing raise issues concerning recovery of transition costs. The requests present a wide range of objections, requests for clarification, and counterproposals to the transition cost provisions of Order No. 636. The major issue is raised by the state commissions, consumer advocates, and LDCs — a charge that the 100 percent passthrough of pipelines' gas supply realignment (GSR) costs through a demand surcharge overburdens the captive customers of LDCs with the costs of restructuring while allotting none of those costs to pipelines, industrial consumers, producers, and marketers — even though the latter groups reap virtually all of the benefits. The Commission has decided on rehearing to respond to this concern by requiring pipelines to recover 10 percent of their GSR costs through their rates for interruptible transportation under their Part 284 blanket certificate.

1. Equitable allocation of GSR costs

a. Proposals to shift costs to other parties

The New York PSC objects to pipelines being allowed to recover 100 percent of their transition costs, arguing they will thus have little or no incentive to minimize such costs. The New York PSC would have the Commission require a sharing of transition cost responsibility between the pipeline and its customers under the guidelines of Order No. 528 or, at a minimum, require pipelines to absorb 10 percent of those costs. The New York PSC would have the remaining unabsorbed costs spread over a broader industry base by requiring an appropriate percentage or fixed unit amount of transition costs to be

recovered on the basis of total throughput. The New York PSC argues that recovering the transition costs through the commodity surcharge would provide pipelines implementing an SFV rate design with an incentive to maximize throughput while more permanent incentive rate mechanisms are under consideration, and significantly mitigate the increased burden being placed on residential consumers by Order No. 636.

Citizen Action argues that the Commission erred in failing to ascertain or even estimate the amount of transition costs that may be incurred as a result of Order No. 636, especially the GSR costs.[458] Citizen Action maintains that transition costs under the rule could range between $2 and $6 billion, and argues that the Commission erred in permitting pipelines to recover 100 percent of their GSR costs. According to Citizen Action, these costs ought to be the sole responsibility of producers and pipelines, not pipeline customers and consumers. Citizen Action urges the Commission to use authority under Section 5(a) of the NGA to abrogate all contracts between pipelines and producers that contain onerous take-or-pay provisions, or prices that exceed market levels, or, alternatively, to prohibit any pipeline passthrough of transition costs associated with reforming such contracts. Citizen Action also would not limit recovery of GSR costs to firm Part 284 transportation customers, but would spread such costs over a wider customer base.

Illinois Power thinks that by permitting pipelines to recover 100 percent of eligible, prudently incurred transition costs through a demand charge, producers will likely insist on recovering 100 cents on the dollar. It recommends that the

458. Alabama Gas and Illinois Power also argue that the Commission erred by not assessing the magnitude of the transition costs and considering whether they were outweighed by the competitive benefits.

Commission use its authority under Section 7 of the NGA to establish a conditioning mechanism under which a pipeline found to be in compliance with Order No. 636 may deny a producer the benefits of open-access transportation, unless the producer agrees to release the pipeline from gas supply contracts for which the pipeline no longer has a market because of Order No. 636. According to Illinois Power, the Commission justifies abrogation of the pipeline sales contracts on the ground that they were entered into during a period when there was not adequate competition. The same holds true, it argues, for the above-market producer contracts. They contend that their proposal is merely a variant on the take-or-pay crediting mechanism instituted under Order No. 500, which the court upheld in *American Gas Association v. FERC*, 912 F.2d 1496 (D.C. Cir. 1990), and that the crediting mechanism did not keep gas from flowing between willing sellers and willing buyers — the only reason stated in Order No. 636 for not adopting such a proposal.

Various commenters on the NOPR submitted estimates of transition costs that might arise from implementation of the final rule. The Commission did not find it necessary to make its own estimate, because most of the costs at issue are costs that pipelines had already incurred or were obligated to incur, and would have been entitled to recover regardless of restructuring. Furthermore, as discussed below, the Commission believes that the costs of realigning contracts should approximately equal the benefits of the realignment.

While many of the LDCs, state commissions, and consumer advocates suggest various regulatory devices for shifting a substantial portion of the GSR costs away from the customers for whom the gas supply was secured and the customers that

will receive the benefit of improved open access transportation service, no one presents any good reason for doing so. They generally allege that since Order No. 636 will benefit all segments of the gas industry, all segments should bear the costs. The Commission believes that the benefits of Order No. 636 indeed will be widespread. Furthermore, the costs of restructuring will be borne in one way or another by all that participate. But the question here is, who should bear the specific category of gas supply realignment costs?

All of these requests are based on two premises: 1) that Order No. 636 will give rise to potentially enormous GSR costs that would not have been incurred but for Order No. 636, and 2) that it is unfair to require recovery of these costs exclusively from the firm customers for whom the pipelines originally contracted to purchase the gas supplies, and those who will avail themselves of the upgraded, open access transportation services. The Commission does not accept either of these premises.

The 100 percent recovery policy of Order No. 636 provides that, upon full compliance with the rule, pipelines will be entitled to recover their prudently incurred GSR costs necessary to reform gas supply contracts in response to customer purchasing decisions during restructuring. The Commission does not accept the premise that the cost of gas under a contract reformed to reflect current demand, together with the costs of reforming that contract, will necessarily exceed the long-term cost of gas under the same contract if it were not reformed.

While pipelines may make lump sum payments to reform such contracts, and such costs will be labeled "Order No. 636 transition costs," the pipelines will presumably receive more favorable prices or other valuable consideration resulting from

contract reformation. If the Commission had not issued Order No. 636, and the contracts in question were not reformed, the pipeline would likely have had to pay the higher prices or be subject to the less favorable contract terms, and, assuming the costs were not excessive due to fraud, abuse, or similar grounds, the pipeline (under a pre-Order No. 636 regime) would be legally entitled to recover the prudently incurred costs of such contracts from its customers. Thus, the pipeline's sales customers and former sales customers that will share the costs of realigning gas supply contracts will also stand to benefit from the realignment of those contracts. Based upon the Commission's substantial experience to date, reformed contracts are considerably more market responsive. Even if the pipeline's former sales customers choose to reduce or terminate their sales entitlements under existing contracts and purchase gas supplies from nonpipeline merchants, the more favorable terms under the pipeline's realigned contracts will benefit them indirectly by affecting the prices that competing merchants can charge.[459]

Order No. 636 does not ask producers to forego the benefits of their gas sales contracts that were entered into on terms that were presumably reasonable at the time. Generally, the Commission has no jurisdiction over the prices or terms of pipelines' contracts with producers.[460] The Commission in Order No. 636 does not seek to deprive pipelines of a reasonable

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459. Customers that have never been sales customers of the pipeline may also benefit from the availability of the pipeline's portfolio of realigned gas contracts, either by purchasing gas from the pipeline, or as a result of the effect of the prices offered by the pipeline on prices of competing merchants.

460. The Commission's jurisdiction over most producer/pipeline supply contracts has already been removed under the NGPA. As of January 1, 1993, there will be no remaining vestiges of such jurisdiction by virtue of the Decontrol Act.

opportunity to recover the costs of realigning their gas supply contracts under which full recovery of gas costs was guaranteed by Section 601(c) of the NGPA and the Commission's PGA regulations. None of the requests for rehearing is persuasive that such steps should be taken.[461] For one thing, pipelines have already absorbed a substantial amount of take-or-pay and realignment cost under Order Nos. 500 and 528. The Commission's records indicate that as of June 30, 1992, pipelines have made filings under those orders concerning nearly $10 billion, and have agreed to absorb nearly $ 3.6 billion of such costs (36.6 percent), and sought to passthrough the balance of nearly $ 6.4 billion (63.4 percent) to consumers. Of the amount to be passed through, approximately $3.5 billion has been directly billed (55.5 percent), and approximately $2.8 billion (44.5 percent) has been billed through a volumetric surcharge. However, the Commission will require pipelines to recover 10 percent of their prudently incurred GSR costs through their interruptible transportation rates under their Part 284 blanket certificate, as described below, thus further spreading some of those costs to the pipeline's interruptible sales and transportation customers, as discussed below.

b. Contract assignments and prudence reviews

The Wisconsin Distributor Group asserts that if the Commission ever hopes to get Order No. 636 off the ground, it must develop incentives to minimize transition costs. The

461. Accordingly, the Commission will not respond to each specific proposal for mechanisms to shift GSR costs to producers or pipelines — such as conditioning producer access to open access transportation on making concessions in contract reformation, or requiring pipeline absorption of some percentage of those costs — because the arguments for shifting the costs are not persuasive.

Wisconsin Distributors contend that, absent some improvement in Order No. 636's treatment of transition costs, many LDCs will be pushed back to pipelines (because they cannot afford to leave) rather than to a competitive marketplace. The Wisconsin Distributor Group also argues that prudence review will not be a meaningful remedy. They assert that prudence cases are very difficult, complex, expensive, and time-consuming, and the party whose actions are in question controls all the documents. Furthermore, they assert that the Commission has not generally pursued allegations of improper pipeline purchasing practices with vigor.

Nor does the Wisconsin Distributor Group find solace in contract assignments as a remedy to mitigate transition costs, because in most instances, they assert, the purchaser would take over a non-market responsive gas contract. In that event, they conclude, the purchaser's gas costs would increase or remain high, and the purchaser would be precluded from meaningful access to competitive gas markets for the life of the assigned contracts. The Wisconsin Distributor Group urges the Commission to afford pipelines and their customers far greater latitude to negotiate GSR cost recovery mechanisms that will provide effective incentives to producers and pipelines to minimize those costs.

The NASUCA also questions the potential for pipelines to mitigate GSR costs by making assignments of their unneeded gas supply contracts to their customers. NASUCA asserts that a pipeline will have no need to jettison its gas supply contracts with competitive, market-based prices — only their non-market responsive contracts. Thus, they argue, captive LDCs may be presented with a Hobson's choice: either pay for non-market responsive contracts through transition costs or pay for them

through contract assignment. NASUCA suggests that the Commission require pipelines to adjust their prices under contracts they seek to directly assign to their customers in order to reflect market-based prices (with any necessary adjustment to reflect the long-term firm nature of the contract) by exercising their rights under any "FERC out" or "government out" clauses. According to NASUCA, Order No. 636 creates a situation for pipelines that makes it financially impossible for them to perform under existing contracts because the Commission has permitted the abrogation of the pipeline/customer sales contracts that initially supported the producer contracts. Therefore, they argue, pipelines' diligence in asserting their rights under any such "FERC out" or "government out" clauses should be a standard for establishing their prudence in incurring any GSR costs.

A pipeline's Part 284 transportation customers, including formerly, bundled firm sales customers, will be presented with various choices for arranging for gas supply and enhanced transportation options when the pipeline implements Order No. 636. The Wisconsin Distributor Group and NASUCA correctly point out that none of the choices avoids the prudently incurred costs of gas supply under the pipeline's existing portfolio of contracts. But, the Commission is attempting to provide pipelines and their customers with equitable means to effectuate a transition, not some device for avoiding existing contracts with no reasonable provision for compensation. Pipelines and producers are encouraged to offer assignments of their unneeded gas supply contracts, and if they do, are required to make such offers on a nondiscriminatory basis. But a pipeline's customers are not required to accept such assignments if they conclude that other means of paying the pipeline's GSR costs are more advantageous.

Prudence reviews are intended to provide a meaningful

remedy for imprudence, not to force absorption of costs by pipelines for decisions that were prudent under the circumstances. The Commission's past review of prudence challenges is criticized because the Commission has failed to find imprudence in circumstances where the record did not warrant such a finding. But the Commission's responsibility is to find imprudence only when it is shown. Given the importance of prudence challenges in the future, the Commission will consider prudence challenges in a timely and vigorous manner. Simply put, the Commission will carefully examine prudence challenges in proceedings to recover Order No. 636 transition costs to ensure that those costs have been minimized.

If pipelines have rights under their producer supply contracts to adjust the price or terms of those contracts, of course they should exercise those rights for the benefit of their customers. A failure to do so would clearly be imprudent. However, the Commission cannot construe what the contractual rights of parties may be under contract clauses that are not before us, and indeed, the Commission's jurisdiction to construe contracts between pipelines and producers is quite narrow.

c. Shifting costs to producers

According to the NASUCA, the Commission has authority under Section 5 of the NGA to abrogate the non-market responsive contracts between pipelines and producers, and should place producers with jurisdictional contracts on notice that any failure to renegotiate such contracts in good faith could result in abrogation. The Commission's decision not to exercise Section 5 abrogation authority in Order Nos. 500-H and 500-I is not dispositive, they argue. Under those orders, the parties sought to circumvent the take-or-pay clauses of producer/

pipeline contracts with claims that competitive conditions made compliance with the take-or-pay provisions difficult. However, according to NASUCA, economic and competitive trends in the industry do not form the basis for invoking Section 5 authority against producer contracts in restructuring proceedings. Rather, they argue, the Commission's use of that authority to abrogate contracts between pipelines and their customers mandates equal treatment on the pipelines' supply side.

The Tennessee and Columbia Small Customers argue that a producer's access to additional firm transportation and storage capacity that becomes available as a result of restructuring should be linked with the reformation of the producer's existing gas supply contracts. This linkage is justified, according to these customer groups, because the producers will be enabled to compete in markets from which they are currently excluded as a result of the pipelines' competitive advantages. Furthermore, they assert, implementation of the SFV rate design is likely to increase producer netback prices by shifting costs out of the pipelines' usage charges.

These small customer groups also say that producers will not accept settlements that approach the level of discounts they reportedly agreed to in connection with take-or-pay contract settlements under Order Nos. 500 and 528, because the uncertainties and risks surrounding the enforcement of gas sales contracts at the time of those negotiations no longer exist. Producers may even be able to extract premiums for contract reformation, they argue, because the timetable adopted for compliance with Order No. 636 will severely disadvantage pipelines in negotiating buydowns and buyouts, and may force them to offer "sweeteners" even to renegotiate market-clearing contracts.

Appendix C

In Order No. 636, the Commission stated that pipelines must take all possible steps to minimize transition costs in the course of realigning their gas supply contracts. Many of the LDCs, state commissions, and consumer advocates (and even one pipeline[462]) urge the Commission to afford pipelines additional commercial leverage in these negotiations to extract concessions from producers. Their unstated premise is that if prices under existing, valid, long-term gas supply contracts are higher than current market prices, producers should have to relinquish some part of their benefits under those contracts as a remedy.

If a pipeline entered into an existing gas supply contract in a prudent fashion, even though prices and terms in the market are now more favorable, the Commission strongly urges the pipeline and its supplier to aim for a fair adjustment of the terms of the contract to bring it into line with current and future market conditions. Moreover, as the Commission stated in Order No. 636, the added presumption of prudence afforded to costs filed for recovery under Order Nos. 500 and 528 does not apply to GSR costs.[463] Thus, pipelines have an incentive to renegotiate to minimize costs. And if past practices are a future indicator, producers will recognize that they may not receive the full benefit of a reformation bargain if part of the pipeline's costs are later judged to be imprudent.

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462. Tenneco proposes, *inter alia*, that in order to provide an incentive to producers to make concessions in the renegotiation of uneconomic contracts, pipelines should be permitted to collect an additional demand or commodity charge for transportation of gas purchased from producers that have refused to renegotiate such contracts. The Commission has repeatedly rejected such conditioned access in the past and will do so here.

463. "[T]he policies of Order Nos 500 and 528 . . . will generally not be applicable to recovery of gas supply realignment costs attributable to this rule . . . ." "[Pipelines] will not be afforded protection from challenges to their prudence in this matter." Order No. 636 at p. 30,460.

Appendix C

d. Spreading costs to interruptible and 7(c) shippers

The Iowa, Missouri and Wisconsin Commissions question the wisdom of allowing GSR costs to be recovered through a reservation fee surcharge or exit fee, neither of which will be applicable to interruptible transportation service or transportation under individual NGA Section 7(c) certificates. They assert that historic sales customers that might elect to leave the system to pursue a least-cost purchasing strategy will be discouraged from doing so if pipelines are permitted to impose exit fees. A customer leaving one system to purchase gas on another will have to pay an exit fee on the first and reservation charge on the second. They also argue that permitting a pipeline to recover its GSR costs primarily from one group of customers, the LDCs that historically were resellers, will handicap those customers in competing with the pipeline as merchant, independent marketers, and producers — who do not bear these costs — in the competition for sales to prime, high-load factor users. The Iowa, Missouri, and Wisconsin commissions conclude that the solution is obvious: spread transition costs among the full universe of users of the pipeline's services on a strict volumetric basis.

The CPUC also argues that there is no reason why the pipelines' interruptible transportation customers should not have to pay a part of the transition costs, and that excusing them from these costs is a radical and arbitrary departure from the policies of Order No. 528. Furthermore, the CPUC asserts, by singling out firm transportation customers to pay the transition costs, the Commission has encouraged many customers to become interruptible transportation customers, rather than participate in the firm capacity reallocation programs, thus further concentrating the burden of these costs on firm transportation

customers such as LDCs. Like the other state commissions, the CPUC also recommends a volumetric surcharge on transportation service as the mechanism for recovery of GSR costs, asserting that on many pipelines, the amounts of volumetric surcharges under Order Nos. 500 and 528 have diminished to insignificant levels (4¢/dth for El Paso, 1¢/dth for Transwestern), and arguing that additional surcharges would not jeopardize producers' revenues and production.

The National Association of Gas Consumers asserts that GSR costs will be caused by decreases in the volume of gas purchased, not the peak demands. Therefore, high load factor customers will cause more gas supply realignment costs per unit of demand, but will pay the same charge per unit of demand. The National Association of Gas Consumers argues that this situation should be remedied by including any allowed transition costs in the transportation commodity charge.

The Commission generally follows the principle that assessment of costs should reflect cost causation principles. The prescribed surcharge on reservation fees for firm transportation under a pipeline's Part 284 blanket certificate is an appropriate means of recovering the bulk of GSR costs, because such a surcharge spreads the costs over a broad group of the pipeline's customers that will benefit from the improved quality of transportation mandated by the final rule. The Commission also recognizes that to effectuate an equitable transition to a more competitive market, it is necessary to allow short-term assessments to be spread over a broader customer base. On rehearing, therefore, the Commission has decided to require pipelines to recover 10 percent of their prudently incurred GSR costs through their interruptible transportation rate for interruptible service under their Part 284 blanket certificates. Pipelines must therefore allocate 10 percent of their GSR costs

to their interruptible service to be recovered in their interruptible rates, not in the form of a surcharge, but as a cost allocated to that service. Furthermore, in order to avoid double charging interruptible transportation customers, pipelines must exclude the GSR surcharges on the firm reservation fee in calculating the amount of fixed costs to be recovered through interruptible rates, as in, for example, the derivation of an interruptible rate from the firm reservation fee. This modification of the recovery mechanism for GSR costs will permit collection of a part of the GSR costs from the pipelines' open access interruptible customers — customers that would not have been subject to assessment of any such costs under the final rule.

The Commission recognizes that the uncertainties surrounding any estimates of interruptible throughput after restructuring may make it difficult to design interruptible rates that will assure pipeline recovery of the GSR costs. But the Commission does not intend for pipelines to have to absorb the portion of GSR costs assigned to interruptible transportation, and encourages the pipelines and the parties to the restructuring to be creative in fashioning rate mechanisms, such as an appropriate true-up mechanism, that provide a reasonable opportunity for pipelines to recover (but not overrecover) those costs.

Assessing 10 percent of the transition costs to interruptible rates will be short term, not a permanent feature of pipelines' rates, and constitute a pragmatic adjustment to Order No. 636. The Commission finds this to be a reasonable transitional trade-off in light of the rule's long-term benefits.

2. What constitutes gas supply realignment costs?

The Illinois Commerce Commission requests clarification

of what constitutes a pipeline's GSR costs, whether this cost is the difference between the cost of gas under the pipeline's existing portfolio and the cost of a portfolio of gas with similar volumes and durations if purchased today — *i.e.*, the amount by which the portfolio is above market — or the cost of buying out all of the pipeline's above-market contracts. If the latter view is taken, the Illinois Commerce Commission asserts that pipelines will be able to reap a windfall by divesting themselves of all above-market contracts, billing their customers for those buy-outs, and marketing the gas under their remaining contracts (with prices at or below market) at market-based prices. The Northern Distributor Group argues that a pipeline's costs of realigning its above-market contracts should be offset against the capitalized or present value of the below-market contracts it retains or assigns to an affiliate.

The Iowa, Missouri, and Wisconsin Commissions question whether a pipeline will be able to "cherry-pick" among its most favorable supply contracts and pass through the costs of selective buyouts of its most onerous above-market contracts. If so, the state commissions assert, capacity users will bear the costs of the contracts that the pipeline's management elects to shed, and the pipeline, as a marketer, will be free to market a choice mix of gas under the better of its contractual arrangements. Philadelphia Electric suggests that a substantial portion of the GSR costs should be recoverable through a volumetric surcharge to prevent pipelines from reforming their portfolio of supply contracts to below market prices and passing all of the costs of such reformations through as demand surcharges.

Pipelines may not use the reservation fee surcharge to recover GSR costs as a tool for reducing their gas supply portfolios to below-market price levels. There may be disputes about how much cost a pipeline may prudently incur to realign

its supply portfolio, and to what extent its retained portfolio of contracts should serve to reduce its claims for GSR costs. The Commission will consider these concerns on a case-by-case basis as they arise. In the meanwhile, pipelines must act with prudence, good faith, and due regard to their customers' best interests in this matter.

The Iowa, Missouri, and Wisconsin Commissions also suggest that Order No. 636 failed to establish a "bright line" between GSR costs and take-or-pay costs recoverable (with partial pipeline absorption) under the guidelines of Order No. 528.[464] They argue that the ambiguities of the Commission's discussion of this distinction invite extreme positions and posturing in individual cases, as pipelines seek to recover everything but the kitchen sink under Order No. 636, and customers seek to exclude virtually everything. Tenneco asks for clarification that the costs of realigning gas supply contracts incurred after the issuance of Order No. 636, but before the Commission's approval of the pipeline's compliance filing will qualify for 100 percent recovery.

According to the Kentucky PSC, the Commission properly recognized that pipeline actions to restructure their out-of-line gas purchase contacts to reflect market conditions are not, or should not have been, a new activity, and can by no means be attributed solely to the restructuring requirements of Order No. 636. The Kentucky PSC urges the Commission to make clear that costs and liabilities related to service provided prior to the effective date of restructuring cannot qualify as Order No. 636 transition costs.

The CPUC argues that the eligibility standard for recovery

464. Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 53 FERC ¶ 61,163 (1990).

of GSR costs under Order No. 636 is virtually meaningless, because no basis was provided for distinguishing GSR costs resulting from Order No. 636 from costs that arise independently of that order. The CPUC asserts that PGT has never filed with the Federal Energy Regulatory Commission to recover take-or-pay settlement costs under the equitable sharing mechanism, but is presently faced with numerous take-or-pay types of lawsuits and claims. Moreover, CPUC argues that pipelines such as PGT still have take-or-pay exposure because they have not been diligent during the past ten years in reforming contracts and shedding gas supplies, and is concerned that Order No. 636 will provide an opportunity for such pipelines to evade the equitable sharing mechanism.

Maryland People's Counsel is also concerned that the greatest GSR costs will be incurred by pipelines that have been the most recalcitrant or reluctant in restructuring their supply contracts under Order Nos. 500 and 528. Therefore, the customers who have suffered the financial consequences of their earlier lack of access to competitively priced markets, and their pipeline suppliers' reluctance to allow conversion to transportation, will now bear the full financial brunt of mandatory restructuring and the 100 percent passthrough of their pipelines GSR costs. Maryland People's Counsel concludes it would be grossly unfair to assure 100 percent passthrough of take-or-pay buyout and buydown costs to pipelines that previously failed to take the necessary steps to reform their contracts.

Tejas urges the Commission to clarify that pipelines were obligated to buy down their gas portfolios to a competitive market responsive level under Order No. 436, and to flow those transition costs through under Order No. 528, and that only those additional costs incurred by pipelines to reduce the size of their

market responsive portfolios to adjust to a smaller unbundled sales market should be defined as properly recoverable under Order No. 636.

Obviously there are some similarities between take-or-pay settlement costs and GSR costs. On the other hand, there are important differences that now warrant the different policies on absorption. Order No. 436 provided strong incentives to, but did not compel, pipelines to offer open access transportation service, which led in turn to increased take-or-pay liabilities. Under Order Nos. 500 and 528, pipelines were encouraged, although not compelled, to absorb some of the costs of entering into contracts that gave rise to that liability. The policies of Order Nos. 500 and 528 were designed to fairly apportion the substantial portion of buyout and buydown costs without attempting to ascribe blame to any one segment of the industry.

Now, Order No. 636 requires pipelines to restructure their services to afford all consumers with opportunities to fully realize the benefits of a competitive market in natural gas. Pipelines have no choice, however, but to implement the restructuring required under Order No. 636. Pipelines must realign their existing portfolio of gas supply contracts to adjust to their customers' purchasing decisions and to greater competition from other merchants. Order No. 636 requires pipelines to restructure their services and operations to avail their competitors unprecedented access to the pipelines' historic sales customers, and permits those sales customers the choice of reducing their obligations under their existing sales contract. In these circumstances, it is not equitable to require pipelines to absorb further the costs that result from those requirements.

Guidelines and policies will be developed to distinguish precisely between Order No. 528 costs and the costs attributable

to Order No. 636 costs as the Commission addresses disputes in concrete cases.[465] There may be circumstances that militate against 100 percent recovery of the costs of a contract reformation under Order No. 636, and, as the Commission said in Order No. 636, where the total sum of GSR costs is partially eligible and partially ineligible for 100 percent recovery, the parties should devise an appropriate allocation among the two recovery mechanisms.

Moreover, the Commission will clarify that the use of a surcharge on transportation rates to recover GSR costs will be limited to such costs that arise as a result of customers' decisions as a result of the restructuring proceedings. If sales customers reduce or terminate their sales entitlements upon expiration of their contract terms after restructuring, and the pipeline finds it necessary to further realign supply contracts, the costs of such realignments will not be recoverable through Order No. 636 surcharges on transportation rates, but only through market-based sales rates. Thus, after restructuring is complete, the pipeline should seek to address any future realignment costs in the gas supply agreement with its gas purchasers.

Some parties request that the Commission provide an option for pipelines to voluntarily absorb some portion of their GSR costs to avoid prudence challenges. Nothing in Order No. 636 precludes the pipeline from doing this on a voluntary basis, and the Commission encourages all parties to be flexible in dealing with transition cost recovery issues.[466]

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465. *See, e.g.*, Florida Gas Transmission Company, 59 FERC ¶ 61,413 (1992)(gas supply realignment costs incurred in December 1991 and January 1992 not eligible for recovery under Order No. 636 recovery mechanisms).

466. Any costs that would qualify for recovery as GSR costs could be (Cont'd)

3. Exemptions from demand surcharge on firm transportation

NGSA requests rehearing of the decision to have surcharges for GSR costs imposed on the reservation fees for *all* transportation under a pipeline's Part 284 blanket certificate. NGSA notes that transportation rates for service under individual Section 7(c) certificates are not subject to the surcharge, presumably because the provision of such services is unrelated to any gas supply realignment costs. However, NGSA argues that firm transportation service under Part 284 that commences after a pipeline completes restructuring, and is unrelated to service conversions by the pipeline's sales customers should also be exempt from GSR cost surcharges.[467] According to NGSA, to impose surcharges on such service departs from the principle that cost responsibility should follow cost causation.

The Virginia Electric Power Company (VEPCO) argues that the firm transportation service it receives from Columbia Gas Transmission Corporation under Columbia's Part 284 certificate should be exempt from the surcharge for GSR costs because VEPCO was never a sales customer of Columbia, and the facilities used to provide the service were constructed, with an

(Cont'd)

filed for recovery under Order No. 528. Since challenges to a pipeline's prudence in the incurrence of take-or-pay costs are generally avoided when they file for recovery under Order No. 528, pipelines continue to have, at their election, this option.

467. American Paper Institute argues that GSR costs are attributable solely to those currently being served by the pipelines' merchant function, and the responsibility for such costs should rest solely with those existing sales customers. See also, Florida Power and Light Company's (Florida Power) request for rehearing.

contribution in aide of construction from VEPCO, pursuant to a case-specific Section 7(c) certificate. Therefore, VEPCO argues, its service did not displace pipeline sales, and it was not the beneficiary of capacity made available as a part of Columbia's transition from merchant to transporter. Both NGSA and VEPCO point out that many of the firm transportation transactions initiated in the past few years under Part 284 blanket certificates are identical in all respects with firm transportation initiated earlier under individual Section 7(c) certificates, and argue that they would have been certificated under individual certificates but for the Commission's policy against granting such certificates to pipelines that hold Part 284 blanket certificates.

On the other hand, Philadelphia Electric seeks rehearing of the decision to exempt long-haul market-area Section 7(c) transportation from any transition cost responsibility. Philadelphia Electric asserts that shippers under individual Section 7(c) certificates will reap the same benefits under Order No. 636 as shippers under Part 284. Philadelphia Electric asserts that the Commission has consistently required a contribution to take-or-pay costs by individual Section 7(c) shippers,[468] and storage customers,[469] and argues that the apparent departure in Order No. 636 from established Commission policy favoring the broadest distribution of such costs among similarly situated customers is unexplained and arbitrary.

The Commission recognizes that any prospective allocation of GSR costs will depart somewhat from traditional cost

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468. Citing, *inter alia*, Transcontinental Gas Pipeline Corp., 55 FERC ¶ 61,339 at p. 62,004 (1991)

469. Citing CNG Transmission Corp., 51 FERC ¶ 61,158 at p. 61,433 (1990).

causation principles. However, given our limited legal flexibility,[470] and the fact that all Part 284 shippers will benefit from this rule, GSR costs will not be recovered exclusively from former sales customers. If recovery of such costs were so limited, very few sales customers would find it feasible to choose a nonpipeline merchant. The choices that the final rule offers would be diminished, and the benefits of increasing competition at the wellhead would not be fully realized. The Commission sought in Order No. 636 to authorize recovery of these costs from a broader class of customers, namely, all that utilize firm transportation service under a pipeline's Part 284 blanket certificate, and in this order will broaden that class even further to include Part 284 interruptible transportation customers. This class will include current sales customers, former sales customers, customers that reduce or terminate sales entitlements during restructuring, and those that do not. It will also include firm and interruptible transportation customers that have never been, and will probably never be, sales customers of the pipeline. However, in the Commission's judgment, this continues the general goal of spreading the costs of industry restructuring.

Moreover, surcharges and exit fees to recover GSR costs will not be permanent features of a pipeline's rate structure. They are one-time-only or short-term assessments necessary to effectuate the transition to a more efficient, competitive natural

470. *See* Associated Gas Distributors v. FERC, 893 F.2d 349 (D.C. Cir. 1989)(AGD-II). *cert. denied sub nom.* Berkshire Gas Company v. Associated Gas Distributors, 111 S.Ct.277 (1990)(use of purchase deficiency method to allocate take-or-pay costs violates filed rate doctrine); Columbia Gas Transmission Corp. v. FERC, 831 F.2d 1135 (D.C. Cir. 1987) (direct billing of deferred production-related costs under Order No. 94 violates filed rate doctrine); and Transwestern Pipeline Co. v. FERC, 897 F.2d 570 (D.C. Cir. 1990) (direct billing of unrecovered gas costs in Account No. 191 when PGA mechanism had been terminated violated filed rate doctrine).

gas market. Under the circumstances, the Commission believes that spreading the costs of the transition over a broader group of customers than those whose specific choices in restructuring give rise most directly to the pipeline's incurrence of those costs is equitable.

On the other hand, transportation service under individual Section 7(c) certificates is not directly affected by Order No. 636. The provision of such service will not give rise to any Order No. 636 transition costs, and the upgraded, open access transportation services required by the final rule generally will not benefit shippers under individual Section 7(c) certificates. Accordingly, the Commission will deny Philadelphia Electric's request for rehearing.

4. Recovery (or refund) of Account No. 191 balances

ANR requests clarification of the Commission's statement in Order No. 636 that recovery of Account No. 191 costs will be limited to costs accrued after July 31, 1991, the issuance date of the Notice of Proposed Rulemaking in this proceeding, based on the Commission's understanding of the court's decision in *Transwestern Pipeline Co. v. FERC.*[471] ANR argues that the Commission's action in eliminating the purchased gas adjustment (PGA) mechanism in Order No. 636 is distinguishable from the situation in *Transwestern* where the pipeline voluntarily sought direct bill recovery of the balance in its Account No. 191. ANR argues for 100 percent recovery of any balance in its Account No. 191 account when its PGA mechanism is eliminated without regard to any "cut off" date for accrual of its purchased gas costs.

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471. 897 F.2d 570 (D.C. Cir. 1990).

Appendix C

Carnegie seeks clarification that pipelines will not be limited to recovery of Account No. 191 costs *incurred* after July 31, 1991, but that the Commission's reference to costs "accrued" after that date means that pipelines may recover the accumulated balance after that date, regardless of when the costs were incurred. According to Carnegie, a substantial portion of the Account No. 191 balances of many pipelines is attributable to costs incurred before July 31, 1991, and preventing pipelines from direct billing those costs would impose severe losses. Furthermore, they argue, an interpretation limiting pipelines' recovery of such costs would be inconsistent with other statements in Order No. 636 and a statement in an April 28, 1992 letter from Chairman Allday to the President describing Order No. 636 as permitting pipelines "to direct bill *any* unrecovered balances in their purchased gas accounts upon converting to market-based pricing for sales."[472]

Peoples Natural Gas argues that under the decision in *Transwestern*, a pipeline may only direct bill Account No. 191 costs that were accrued into the account after the Commission has explicitly adopted a formula that qualifies as a rate under Section 4 of the NGA and indicates when it will take effect. According to Peoples Natural Gas, the date of issuance of the NOPR in this proceeding cannot serve as notice of a direct billing formula sufficient to satisfy the filed rate doctrine. The proposal was simply a proposal, Peoples Natural Gas argues, to authorize direct billing as a generic concept, and did not announce any particular allocation methodology or formula, so that customers were not informed in even the most rudimentary way of the consequences of direct billing by any particular pipeline.

When a pipeline terminates the operation of its PGA

472. CNG makes the same arguments in a request for clarification.

mechanism, its Account No. 191 balance will either be positive or negative. A positive balance in a pipeline's Account No. 191 is a reflection of unrecovered costs of purchasing gas for a prior period. Customers that purchase gas from a pipeline with a PGA mechanism in its tariff are on notice that they are potentially liable in future periods for payment of unrecovered purchased gas costs that are attributable to current service. If it is negative, the sales customers are entitled to a refund of the pipeline's overrecovery of its purchased gas costs in prior periods. As long as the PGA mechanism remains in place, refunds are made pursuant to the terms of the mechanism itself. When it is terminated, they are made pursuant to any provisions of the pipeline's tariff that provide for disposition of the Account No. 191 balance, or if there are no such provisions, pursuant to Commission order.

The Commission argued in the *Transwestern* case that if a PGA mechanism is terminated leaving a positive balance of unrecovered gas costs in Account No. 191, the pipeline should be entitled to render a final bill to its sales customers to complete recovery of its gas costs for service rendered in prior periods, even if the pipeline's tariff did not have specific provisions for final disposition of such balances in effect when such costs were accrued. In the Commission's view, Transwestern's PGA mechanism, by its very nature, provided adequate notice of customers' potential liability for a positive balance in Account No. 191 upon termination of the mechanism. The court disagreed, holding that the PGA regulations promulgated in 1972 and certain more recent cases authorizing direct billing of Account No. 191 balances did not provide sufficient notice of customers' liability for such direct billing to satisfy the filed rate doctrine. Accordingly, the court disallowed recovery of Transwestern's unrecovered purchased gas costs that accrued before the date the Commission approved Transwestern's

certificate providing for such direct billing upon termination of its PGA mechanism.

The Commission expects pipelines will terminate their PGA mechanisms under Order No. 636 and initiate market-based pricing of gas in order to remain competitive in the sales market after full compliance with restructuring.[473] Accordingly, and in light of the court's decision in *Transwestern*, the Commission gave notice in the NOPR in this proceeding, and again in Order No. 636, to all sales customers of affected pipelines of their liability for any unrecovered balances in those pipelines' Accounts No. 191 upon termination of their PGA mechanisms in connection with restructuring.

Before the Commission's decision in *Transwestern*, pipeline sales customers may not have known that they would be liable for direct bills upon termination of a PGA mechanism. It was the absence of notice of such potential liability, and not the absence of a specific formula for determining the amount of the future direct bills that the court found violated the filed rate doctrine. However, the Commission considers the notice of the Commission's policy on this issue in the NOPR to be adequate notice to permit direct billing of all costs that accrue after that date by all pipelines affected by this proceeding. Furthermore, the Commission does not anticipate that pipelines will have any unrecovered gas costs that accrued before July 31, 1991, by the time they come into full compliance with Order No. 636 and terminate their PGA mechanisms. Most pipelines have already recovered their pre-July 31, 1991 costs, and for those that have not, there is ample opportunity to recover such costs through the operation of their PGA mechanisms before they implement

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473. However, pipelines are not prohibited from negotiating cost-tracking systems with their customers.

their restructuring filings in time for the 1993-1994 winter heating season.

The Commission stated in Order No. 636 that pipelines must permit customers to pay the direct bill for Account No. 191 costs in either a lump sum, over twelve months, or over some other reasonable period of time, at the customer's option. K N Energy asks for clarification that pipelines will be able to collect carrying charges if the payment of the principal amount of the direct bill is amortized over a period of time. K N Energy asserts that the Commission's consistent practice has been to permit recovery of carrying costs.[474] The Commission grants the requests for clarification by K N Energy. A pipeline will be entitled to collect carrying charges on the unrecovered balance of a direct bill that a customer elects to pay in installments at the same rate that would apply to unrecovered balances in Account No. 191.

United Distribution Companies seek clarification that customers may challenge the level and makeup of the balance remaining in Account No. 191 on its termination apart from the issue of the pipeline's prudence in its purchasing practices. They suggest that a pipeline, recognizing that it will have an opportunity to recover prudently incurred Account No. 191 costs, may be tempted to sell its gas supplies at low cost, thereby inflating the Account No. 191 balance. This would not be prudent, according to United Distribution Companies, and customers should have the right to challenge the content of Account No. 191 in such an event. Northern Indiana argues that pipelines should not be allowed to direct bill Account No. 191 balances to its former sales customers that reflect the costs of gas incurred to balance receipts and deliveries of its transportation customers.

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474. Citing, *inter alia*, Trunkline Gas Company, 58 FERC ¶ 61,340 (1992).

The Commission grants these requests for clarification. Customers of a pipeline terminating its PGA mechanism and proposing to direct bill the unrecovered gas costs in its Account No. 191 will have the same rights to challenge the makeup of contents of the account, including costs attributable to the pipeline's transportation service, as they would have in a review of any annual PGA filing.

The Tennessee and Columbia Small Customers assert that recovery of commodity-related Account No. 191 costs based on gas purchases for the twelve months preceding the effective date of service under the unbundled sales certificate, and the recovery of demand costs based on CD on the day before the effective date of restructured services, will have a disproportionate and unfair impact on small sales customers, because many of the larger customers have converted to transportation in the past several years. The small customer groups argue that unrecovered PGA costs should be recoverable from all customers who were sales customers of the pipeline during the period the costs were actually accrued. The Commission has already indicated in Order No. 636 that pipelines or other parties could propose other mechanisms for allocating the Account No. 191 costs to be direct billed, if the described mechanism is inequitable.[475] Accordingly, there is no need to grant rehearing on this issue.

5. Challenges to a pipeline's prudence

In Order No. 636, the Commission stated that a review of a pipeline's prudence in incurring GSR costs would include an examination of whether the contract terms were reasonable in light of the market conditions existing when the contract was

475. Order No. 636 at p. 30,458, n. 283.

negotiated, renegotiated or terminated. NGSA maintains that the language is confusing and could be interpreted to mean that the prudence of contracts renegotiated under the provisions of Order Nos. 500 or 528 could be challenged in connection with their reformation a second time under Order No. 636. Since pipelines that filed for recovery under Order Nos. 500 or 528 absorbed a portion of the contract renegotiation costs involved, and were afforded a presumption of prudence in the incurrence of such costs, NGSA argues that the renegotiated contracts should also be accorded a presumption of prudence in proceedings to recover GSR costs under Order No. 636.

In Order No. 636, the Commission stated that it was not proposing a new prudence standard for review of a pipeline's GSR costs, but also said that its primary objective in any prudence review of such costs would be to determine that the total amount is as minimal as possible. K N Energy, Inc. is concerned that the "as minimal as possible" standard is not the Commission's historical prudence standard of the "reasonable man" test, and requests the Commission to clarify that the applicable test in prudence reviews of GSR costs will be the "reasonable man" test set forth in *New England Power Company*.[476] If the Commission declines to so clarify, K N Energy seeks rehearing, claiming that the Commission has impermissibly deviated from its consistent practice without reasonable explanation. Marathon raises the same issue, arguing that the Commission must resolve how a contract once deemed reasonable is now subject to a reassessment on the same issue.

Tenneco suggests various regulatory incentives for producers to make concessions in reforming their supply

476. 31 FERC ¶ 61,047 at pp. 61,081-84 (1985), *aff'd*, Violet v. FERC, 800 F.2d 280, 282-83 (1st Cir. 1986).

contracts with pipelines. If the Commission does not implement any of these incentives, and does not permit pipelines to implement any of them, Tenneco asks the Commission to explicitly find that pipelines are prudent if they are able to negotiate a buyout or buydown that is equal to or less than a dollar for dollar settlement.

The Commission does not intend for challenges to a pipeline's prudence in incurring GSR costs to reopen prudence issues that have already been resolved. If a contract is renegotiated under Order No. 636 that had not been renegotiated under Order Nos. 500 or 528, interested parties may challenge the pipeline's prudence in entering into the contract in the first place, the prudence of its purchasing practices under the contract (assuming these issues have not been previously litigated), and the pipeline's prudence in renegotiating the contract under Order No. 636. However, if recovery of the costs of renegotiating a gas supply contract has been allowed under a take-or-pay filing made pursuant to Order Nos. 500 or 528, the renegotiation of the contract has been found to be prudent. If the same contract is renegotiated again under Order No. 636, interested parties may challenge the pipeline's prudence in the latter renegotiation, but not the former.

The Commission is not changing its historic standard or test for determining the prudence of a pipeline in purchasing gas supplies. However, as the Commission said in Order No. 636, prudence dictates that pipelines in restructuring proceedings negotiate vigorously and at arms length with their producer/suppliers in a *bona fide* effort to minimize transition costs.[477] A pipeline whose prudence is challenged will be judged on the basis of such effort.

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477. Order No. 636 at p. 30,459.

Appendix C

6. GICs and recovery of gas supply realignment costs

LILCO suggests an additional element for determining the prudence of a pipeline's GSR cost incurrence where the pipeline currently has a gas inventory charge (GIC), namely, whether the pipeline prudently used the dollars it has collected from the GIC to realign its gas supply contracts and thus reduce the GSR costs resulting from restructuring under Order No. 636. LILCO argues that a pipeline should not be permitted to recover 100 cents on the dollar of GSR costs if it has not used the proceeds from its GIC collections wisely and efficiently to reduce its above-market costs.

The Kentucky PSC seeks clarification that pipelines with GICs may not include amounts spent to resolve liabilities accrued when service was provided under the GIC as transition costs under Order No. 636, because GIC mechanisms were supposed to be the sole means for recovering costs necessary to buydown or maintain existing high cost gas supply contracts.

Gas Company of New Mexico asserts that pipelines with GICs had to forego any other method of recovering gas supply costs. Therefore, it argues, any pipeline that has contracts for sales at negotiated rates that include gas inventory charges should not be permitted to charge any otherwise eligible GSR costs to GIC customers unless the customer uses rights provided in Order No. 636 to modify its contract entitlements.

Gas supply costs for which GIC charges have been collected cannot be recovered again as transition costs. For this reason the Commission prohibits a pipeline with a GIC mechanism in place from filing under Order No. 528 to recover take-or-pay costs. However, a pipeline may incur GSR costs as a result of its customers' actions under Order No. 636 that could not have

been anticipated in designing the GIC and cannot be recovered through a GIC. For example, a pipeline may presently be incurring take-or-pay costs and recovering those costs with revenues from its GIC. The pipeline may need to shed the gas contract in order to be competitive in the post-restructuring world. Or the pipeline's customers may choose not to buy any gas from the pipeline after restructuring. The prudently incurred GSR costs attributable to terminating that contract would be eligible for 100 percent recovery under Order No. 636 if the pipeline demonstrates that customer actions pursuant to Order No. 636 caused the GSR costs, were not anticipated in the design of the GIC, and cannot be recovered by the GIC.

7. Small customer exemption, mitigation

The Tennessee and Columbia Small Customers request that small customers be exempt from transition costs associated with restructuring under Order No. 636, particularly the costs of contract realignment and extinguishment of Account No. 191. In the alternative, they request their share of transition costs to be reduced by 50 percent in accordance with the policy for reallocating take-or-pay costs away from small customers under Order No. 528-A.[478] These small customer groups argue that they will not significantly benefit from unbundling and comparability of service under Order No. 636, that they are less able to bear transition costs than other, larger customers, and that service to small customers will not cause pipelines to incur material levels of transition costs. These groups assert that because of their purchase levels, load factor characteristics, the small size of their staffs, and the lack of time, training and experience relative to purchasing gas, they will be hard pressed

478. Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 54 FERC ¶ 61,095 at p. 61,300 (1991).

to maintain the same service levels after restructuring without paying much higher rates. These groups predict that the increased rates will prompt many of their customers to switch to alternate fuels — wood, propane, kerosene, and coal — and that other customers that cannot switch will be burdened with undue economic hardship. The National Association of Gas Consumers also requests that small customers be exempt from transition costs because they will not benefit from restructuring, and will be harmed by increased rates. According to this association, the Commission should state, at a minimum, that small LDCs are free to negotiate a reduction or elimination of transition costs.

In this order, the Commission has modified the final rule in several ways described above to ensure the ability of small customers to secure the benefits of restructuring and mitigate any adverse effects. In view of these significant modifications — including the shift of 10 percent of GSR costs to be recovered through Part 284 interruptible transportation service — small customers should not be unduly burdened by transition costs on most pipeline systems.

8. Special issues concerning downstream pipelines

National Fuel raises several concerns about recovery of transition costs by downstream pipelines. In general, National Fuel urges that downstream pipelines should be authorized to recover 100 percent of the transition costs billed by upstream pipelines on an "as-billed" basis.[479] If a downstream pipeline is direct billed by (or receives refunds from) the upstream pipeline

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479. CNG seeks assurances that the Commission does not expect downstream pipelines to absorb any portion of the transition costs billed to them by upstream pipelines.

before its own restructuring filing is implemented, National Fuel urges that the downstream pipeline should be authorized to accumulate the amounts billed or refunded for subsequent distribution when its own PGA mechanism is terminated. Conversely, National Fuel notes that PGA balance direct bills or refunds may be received by a downstream pipeline *after* its compliance filing has been acted on by the Commission. In that event, according to National Fuel, the downstream pipeline will need a PGA "trailing" mechanism or alternative flowthrough procedure to recover these amounts from (or make refunds to) its former sales customers.

Various pipelines have tariff mechanisms for tracking changes in their transportation costs (Account No. 858). Since the balances in such tracking accounts reflect costs incurred by the pipeline in its capacity as a provider of bundled merchant service, National Fuel argues that they should be treated the same way the Commission treats the Account No. 191 balances. National Fuel also argues that recovery by downstream pipelines of upstream transition costs should not be delayed pending completion of the downstream pipeline's restructuring proceeding.

The Commission does not intend for downstream pipelines to have to absorb any of the transition costs billed to them by upstream pipelines. Accordingly, downstream pipelines will propose mechanisms for flowing through those costs to their own customers. Account No. 858 balances may be direct billed the same way as Account No. 191 balances. Such mechanisms must be included in the downstream pipeline's compliance filing in its restructuring proceeding. Mechanisms should be devised for application in various scenarios — when the upstream pipeline's restructuring is implemented before or after that of the downstream pipeline. Downstream pipelines may not recover

any transition costs from their own restructuring until they have fully complied with the requirements of Order No. 636, but they will not be precluded from flowing through transition costs from upstream pipelines while their own restructuring proceedings are still pending. However, such upstream pipeline transition costs must be clearly identified as such and separately identified on the bills from the downstream pipeline's own Order No. 636 transition costs in order to ensure proper treatment of the latter costs.

9. Challenges to prudence of LDCs' actions in restructuring proceedings.

South Carolina Pipeline Corporation (South Carolina Pipeline) requests the Commission to clarify or retract Order No. 636's language in footnote 288 pertaining to prudence challenges before state regulatory agencies to LDCs' actions in restructuring proceedings. South Carolina Pipeline asks for clarification of several alleged ambiguities in the language of that footnote, and asserts that the Commission erred in inviting states to engage in prudence reviews of the actions of LDCs in restructuring proceedings. South Carolina Pipeline asserts that any attempted review in a state proceeding of an LDC's actions in restructuring proceedings or incurrence of GSR costs is constrained by the Supreme Court decision in *Nantahala Power and Light Co. v. Thornburg*,[480] which, according to South Carolina Pipeline, guarantees LDCs passthrough at the retail level of wholesale rates approved by this Commission. South Carolina Pipeline argues that the only potential exception to the pre-emptive effect of FERC-approved rates is the "*Pike County*

480. 476 U.S. 953, 970 (1986); *see also* Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354 (1988).

doctrine,"[481] under which state commissions may consider the wisdom of a utility's purchase from among several alternate sources where the utility initially had a choice. However, according to South Carolina Pipeline, this exception does not apply to the types of costs involved under Order No. 636, because they could not have been nor can they be avoided by the LDC.

PG&E also requests that footnote 288 be deleted because of the likelihood it will be misinterpreted by state commissions in a manner inconsistent with applicable law under *Mississippi Power & Light Co.* and *Nantahala*. PG&E argues that, even though the Commission, for policy or equitable reasons, may not want its order to have the preemptive effect of requiring state regulatory agencies to permit passthrough of Order No. 636 transition costs approved by the Commission, that preemptive effect derives from the filed rate doctrine and the Natural Gas Act, as interpreted by the Supreme Court, and the Commission has no power to waive the doctrine or consequences of its decisions.

Footnote 288 simply stated existing law: state commissions should determine prudence challenges to LDCs under their jurisdiction in accordance with applicable state and federal law. The Commission observes that LDCs will have some critical decisions to make during the restructuring proceedings — *e.g.* whether or not, or to what extent, to exercise their rights to reduce or terminate their sales entitlements under existing contracts, and arrange for alternate gas suppliers. The Commission does not intend to preempt state commissions from determining whether those customers were prudent in making those decisions during restructuring proceedings. This is consistent with the so-

481. Pike County Light and Power Company v. Pennsylvania Public Utility Commission, 465 A.2d 735, 737-38 (1983).

called "*Pike County* doctrine" respecting purchasing decisions, not contrary to it.

10. Exit fees as a deterrence to competition

Northern Illinois Gas reminds the Commission that in its comments on the NOPR, it warned that the exit fee process could be used to insulate pipelines from competitive pressures and to defeat the underpinnings of a final rule. Now it alleges that the exit fees proposed in the April 23, 1992 filing by Natural are so high, and for so long a term, that Natural would be able to reap monopoly profits for its post-Order No. 636 sale services and impose contractual terms that would prevent competition from ever developing on its system. Natural Gas Clearinghouse and Tejas object to exit fees for recovery of GSR costs that are imposed only on those historical sales customers that choose to reduce or eliminate pipeline purchases. According to Natural Gas Clearinghouse, such exit fees eliminate the free nomination rights promised by Order No. 636, place competing suppliers at a distinct disadvantage vis-a-vis the pipeline merchant, and are no different than the minimum bills which have been consistently outlawed by the Commission since the issuance of Order No. 380.[482] Tejas requests clarification that any exit fees must apply to all former pipeline sales customers, irrespective of who they choose to buy gas from in the post-restructuring market.

The Commission will not address Northern Illinois Gas's arguments against Natural's exit fee proposal in this order. Natural's proposal will be considered together with its

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482. Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 49 FR 22,778 (June 1, 1984), FERC Stats. & Regs. [Regulations Preambles 1982-1985] ¶ 30,571.

compliance filing in its restructuring proceeding.[483] In Order No. 636, the Commission provided that pipelines and their customers *could* negotiate exit fees in lieu of, or in combination with a surcharge on reservation fees for recovering GSR costs.[484] Exit fees were also *suggested* as a means for a firm capacity holder to compensate a pipeline for the release of capacity during restructuring where there is no other customer willing to assume liability for the maximum rate for the released capacity.[485] The Commission did not, however, authorize the unilateral imposition of exit fees on a customer that is reducing or terminating sales, but is not reducing its reservation of transportation capacity. Accordingly, the fears of Natural Gas Clearinghouse and Tejas that unilaterally imposed exit fees may function as a minimum bill and deter customer selection of alternative suppliers are misplaced.

With Natural's proposal in mind, Northern Illinois Gas requests, among other things, that pipelines not be allowed to recover the costs of buying out of all their gas supply contracts for the purpose of abandoning the merchant function. According to Northern Illinois Gas, buying contracts down to price levels that reflect long-term firm contract prices may be a legitimate need under Order No. 636, but the costs of abandoning the merchant function altogether is not related to Order No. 636.

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483. Natural Gas Pipeline Company of America, 59 FERC ¶ 61,251 (1992).

484. Order No. 636 at p. 30,457.

485. Order No. 636 at p. 30,454. As long as a sales customer remains on the system as a firm transportation customer of the pipeline, the pipeline has no need of an exit fee, because it can recover a portion of the GSR costs through the demand surcharge.

Appendix C

Pipelines must act prudently to minimize their transition costs. If all customers terminate their sales entitlements during restructuring, a pipeline may have to buy out all of its gas supply contracts and wholly abandon the merchant function, and the prudently incurred costs of such buyouts, to the extent they were attributable to Order No. 636, would be fully recoverable. But a pipeline's costs of buying out of all of its supply contracts, simply because it chooses to get out of the merchant business, and not because its customers so choose, would not be fully recoverable as GSR costs.

11. Columbia's producer contract rejection costs

Columbia and the Official Committee of Unsecured Creditors of Columbia Gas Transmission Corporation (Columbia Unsecured Creditors) urge the Commission to recognize the recoverability of the costs that Columbia will incur as a result of its rejection of various producer contracts in its pending bankruptcy proceeding. Columbia argues that its producer contract rejection costs should be treated as GSR costs under Order No. 636, because they would have been incurred as such costs in the absence of Columbia's actions in the bankruptcy. Columbia is concerned that the Commission may disallow 100 percent recovery of its producer contract rejection costs because they were incurred before issuance of Order No. 636, and thus independently of the final rule. Columbia Unsecured Creditors seek clarification that the Commission will permit recovery of Columbia's gas supply realignment costs either through existing recovery mechanisms or through the new mechanisms established for GSR costs in Order No. 636. The unsecured creditors argue that Columbia's gas supply realignment costs, in the form of producer contract rejections costs, are attributable to the Commission's ongoing regulatory reforms, including Order No. 636.

UGI takes the position that Columbia's producer contract rejection costs are not the consequences of Order No. 636, but stem solely from Columbia's failure to bring its gas supply into line with pre-Order No. 636 market conditions.

As already discussed above, gas supply realignment costs not attributable to restructuring Order No. 636 cannot be recovered as Order No. 636 transition costs. Since this issue or how to treat costs incurred pursuant to rejections of producer contracts in a bankruptcy proceeding is specific to Columbia, the Commission will not address it in this order on rehearing. The issue may be presented by appropriate pleadings in a Columbia proceeding.[486]

12. Great Plains synthetic gas

Several parties raise concerns with respect to the recovery of the cost of synthetic natural gas (SNG) purchased from the Great Plains Gasification Project (Great Plains). In Order No. 636, in response to the comments of the Dakota Gasification Company, the owner of Great Plains, the Commission noted that in the Transco proceeding in Docket No. CP88-391-004, *et al.* (*Transco*),[487] the Commission approved a settlement that provided for a volumetric surcharge on system throughput to recover the above-market gas costs and associated transportation costs related to Transco's obligations to purchase synthetic gas from Great Plains. The Commission stated that it would consider any proposals in the restructuring proceedings of the other

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486. Similarly, Columbia's questions concerning the recoverability of its PGA surcharge under a 1985 settlement are not appropriate for resolution in this generic rulemaking.

487. 55 FERC ¶ 61,446 (1991).

pipelines that purchase synthetic gas from Great Plains, in addition to Transco, for a special billing mechanism and special treatment for the associated transportation capacity for Great Plains gas consistent with the precedent in Transco's global settlement.

The Industrial Groups request clarification that the Commission has not decided in Order No. 636 how these costs shall be recovered, but has instead left that issue for decision in individual restructuring proceedings. In the alternative, if the Commission does not grant the requested clarification, the Industrial Groups urge the Commission to grant rehearing on this issue and to require recovery from converting sales customers only.

Natural maintains that because of intense competition, it would not recover Great Plains coal gas costs if recovery were through a volumetric surcharge. Consequently, Natural requests the Commission to clarify that Order No. 636, while permitting the *Transco* approach, does not require it. Similarly, Tenneco requests the Commission to clarify that it is not precluding recovery of the above-market premiums under the Great Plains contract through a fixed charge across all services.

On the other hand, the State of Michigan argues that the Commission erred by not foreclosing ratepayer subsidization of uneconomic SNG. Similarly, the Wisconsin Distributor Group maintains that the concept of permitting special cost recovery for above-market, inefficient synthetic gas supply costs is contrary to the goals of Order No. 636 to stimulate the domestic natural gas market and to provide customers access to market-priced gas supply.

The Commission recognizes that providing a special cost recovery mechanism for these gas supplies departs from the market-oriented goals of Order No. 636, but it is consistent with the Commission's goal of providing a smooth transition from the prior regulatory environment to the new market-oriented environment. This is particularly appropriate with respect to Great Plains gas because of the special circumstances and government involvement surrounding the Great Plains project. As in *Transco*, the Commission concludes that it is "reasonable for all of [the pipeline's] customers to share in the above-market costs of the nation's first large-scale synthetic fuels plant, whose technological benefits would have redounded to all future gas users . . . by increasing the supply of available gas."[488] Thus, the Commission adheres to its discussion on this issue. The Commission will consider any proposal by the pipelines for recovery of the costs of Great Plains gas, whether or not modeled on the proposal approved in *Transco*.

13. LDC bypasses

A number of parties raise various concerns with respect to LDC bypasses. Several parties (United Distribution Companies, Northern Illinois Gas, and the State of Michigan) assert that the Commission should have established a policy or rule requiring that transition costs follow bypassing customers and/or providing LDCs with relief in bypass situations such as a reduction in contract demand with the pipeline. On the other hand, the American Paper Institute and the Fuel Managers Association maintain that the Commission erred in providing an opportunity for LDCs to obtain relief in the event of a bypass. They assert that offering LDCs relief from bypass is protecting them from competitive forces and is contrary to the principles of competition discussed in Order No. 636.

488. 55 FERC ¶ 61,446 at p. 62,341 (1991).

CNG asserts that because pipelines may confront bypass situations identical to those confronting LDCs, the Commission should clarify that pipelines may request the same relief as LDCs.

Finally, the Iowa, Missouri and Wisconsin Commissions maintain that the Commission's proposed burden of proof on LDCs is misplaced. They urge that once an LDC shows that it has historically supplied a customer that is seeking to bypass its system, and has identified a rational method for allocating to that customer a portion of the transition costs that the LDC is required to bear under Order No. 636, then the burden should shift to the customer that is bypassing the LDC system to show that the proposed allocation is unreasonable or inequitable and that another allocation is more equitable under the circumstances.

The Commission adheres to its views on this issue as set out in Order No. 636. The Commission will consider requests for relief on a case-by-case basisin the context of the new regime of this rule, but will not adopt a policy that would grant automatic relief in all circumstances. The factual circumstances surrounding an LDC bypass differ sufficiently that the Commission cannot justify a generic rule that would be appropriate in all circumstances.

Finally, contrary to the assertions of the state regulatory commissions, the Commission believes that it is fair for an LDC seeking relief in a bypass situation to show that there is a direct nexus between the bypass and the pipeline, so that the costs it seeks to avoid should be reallocated to the bypassing customer. On the other hand, the Commission will not allow bypass to be used simply as a means of avoiding the bypassing company's fair share of transition costs.

Finally, the Commission denies CNG's request for clarification. The Commission has provided pipelines a meaningful opportunity to recover their prudently incurred transition costs. The Commission does not believe it is appropriate for pipelines to obtain additional transition cost recovery on a case-by-case basis every time a shipper switches from one pipeline to another.

14. Miscellaneous

a. Non-cash consideration as GSR costs

PSE&G requests clarification that if pipelines realign their producer supply contracts by providing for discounted transportation or other non-cash consideration, they will not be allowed to recover the costs of such settlements as GSR costs.

The precedents under Order Nos. 500 and 528 governing recovery of non-cash consideration to reform gas supply contracts are applicable.[489]

b. Alternative recovery mechanisms

United Distribution Companies argue that Order No. 636 unduly restricts parties from negotiating alternative methods of

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489. *See* ANR Pipeline Company, 48 FERC ¶ 61,140 (1989)(non-cash consideration to settle take-or-pay contracts was recoverable through a take-or-pay recovery mechanism if it met the known and measurable standard). However, the only costs of transportation discounts that are recoverable through a take-or-pay mechanism are the costs of discounting below the level of discount that the pipeline is giving other shippers at the time for competitive reasons. Natural Gas Pipeline Company, 51 FERC ¶ 61,190 (1990), and United Gas Pipe Line Company, 51 FERC ¶ 61,320 at p. 62,065 (1990).

transition cost recovery. CNG LDCs agree, and urge the Commission to withdraw its prescribed recovery mechanisms for transition costs, and grant the parties an opportunity to negotiate the means by which transition costs are to be recovered.

Order No. 636 does not preclude parties from voluntarily agreeing to alternative mechanisms on the basis of the pipeline's particular circumstances. However, in the absence of such voluntary agreement between the pipeline and the parties, Order No. 636 will control.

Western Resources (formerly KP&L) asserts that its pipeline supplier, Williams Natural Gas Company, entered into its gas supply contracts to serve both its firm and interruptible customers, and that many current shippers were interruptible sales and non-jurisdictional customers prior to Williams' transition to open-access transportation, and argues that GSR costs should be recovered through a volumetric surcharge to reach those customers.

As discussed above, interruptible shippers under a Part 284 blanket certificate will be subject to an interruptible rate that recovers 10 percent of a pipeline's GSR costs. Furthermore, as discussed below, when a pipeline unbundles its direct, non-jurisdictional sales, the unbundled transportation will be provided under the pipeline's Part 284 certificate, and will be subject to surcharges to recover Order No. 636 transition costs.

c. Recovery of GSR costs through direct bill or exit fee

Phillips urges that 50 percent of GSR costs and stranded facility transition costs should be recoverable through a direct

bill or exit fee and that 50 percent should be recoverable through a demand surcharge.[490] Phillips alleges that in today's market, all transportation costs, including demand surcharges, are typically "netted-out" from the prices producers receive at the wellhead. According to Phillips, using a 100 percent demand surcharge mechanism to recover GSR costs and stranded facility costs could leave producers absorbing the lion's share of the two largest elements of transition costs.

For most gas sales, a demand surcharge will have no effect on the purchaser's decision to buy a certain increment of gas and will not affect wellhead prices. A customer that has entered a long-term contract is obligated to pay the monthly demand charges, and any demand surcharges, regardless of whether it purchases any gas, and regardless of what price it pays for the gas. In Order No. 636, the Commission provided that exit fees for recovery of GSR costs could be negotiated. However, the Commission will not require customers to pay exit fees or permit them to direct bill for the recovery of GSR costs.

d. Effects of existing settlements on transition cost recovery

Washington Gas seeks clarification that Order No. 636 does not void existing settlements approving restructuring and transition cost recovery, but that the viability of the settlements, in whole or in part, will be tested and determined in the separate pipeline restructuring proceedings. Washington Gas urges the Commission not to dismiss the possibility that existing

490. The Commission in Order No. 636 did not prescribe any generic recovery mechanism for stranded costs, but merely provided that pipelines could propose an appropriate means of recovering all prudently incurred stranded costs in a general rate filing under section 4 of the NGA.

settlements already reflect the maximum degree of achievable unbundling consistent with certificated firm service levels under Section 7(c) of the NGA and prudent and reasonable transition cost levels. Washington Gas argues that any determination of the continued viability of existing settlements, and any findings that they violate Section 5, should be made at the end, not at the beginning, of the restructuring proceedings. BG&E also seeks clarification that previously approved Order No. 528 settlements remain binding and govern the treatment of any gas supply realignment or similar costs that fail to pass the Order No. 636 eligibility review.

Atlanta Gas also seek assurances that ceilings under existing take-or-pay settlements will not be disturbed by permitting recharacterization as GSR costs under Order No. 636, nor will the protection against abandonment negotiated in the settlement of Transco's restructuring be disturbed.

As noted in Order No. 636, the relationship between provisions of existing settlements and the provisions of Order No. 636 will have to be examined on a case-by-case basis. The Commission has and will provide all interested parties with an opportunity to present arguments on this issue on a pipeline by pipeline basis. However, as Washington Gas recognizes, settlements, like any other contracts, may be subject to revision if necessary to remedy violations of the NGA. However, Order No. 636 is not intended to affect the provisions of existing settlements governing recovery of take-or-pay costs under Order Nos. 500 and 528.

e. Credit for taking assignment of supply contracts

Illinois Power seeks clarification that customers taking

assignments of producer contracts will receive a credit against the transition costs otherwise allocable to them.

To avoid transition costs the Commission strongly encourages pipelines and parties to consider assignment of their gas supply contracts in their restructuring proceedings, where such assignments are mutually beneficial as a way of avoiding transition costs. However, the details of how the customers that accept such assignments should be treated in comparison to those that do not, as far as responsibility for transition costs, must be worked out in the restructuring proceedings.

f. Transition cost recovery and retroactive ratemaking

The National Association of Gas Consumers argues that GSR costs, Account No. 191 costs remaining when a PGA mechanism is terminated, and "stranded costs" are past costs that will not recur during the period that the restructuring rates will be in effect, and that the ban on retroactive ratemaking prohibits collections of these costs from consumers.

The ban on retroactive ratemaking should not prevent pipelines from recovering any of the transition costs arising from restructuring. GSR costs are the costs of reforming supply contracts under which gas will be available on a current basis. Unrecovered purchased gas costs relate to gas purchases in a prior period, but are recoverable on a deferred basis pursuant to the notice in this proceeding's NOPR (and elsewhere) of pipeline customers' direct bill liability for such costs upon termination of the PGA mechanism. Liability for stranded costs is based on the availability of the pipeline's facilities for future use by the system even though they are not directly assigned for use by a specific customer.

g. 100 percent recovery by pipelines and the "used and useful" principle

The CPUC argues that requiring a pipeline's customers to bear all of the transition costs is contrary to the "used and useful" principle discussed in Order No. 528-A as a justification for requiring equitable sharing.

The Commission has described the reasons for its different policies for Order No. 528 costs and Order No. 636 costs, *supra*. The analogy described in Order No. 528-A between pipelines' high-cost take-or-pay contracts and certain failed gas supply projects, which the Commission had concluded were not used and useful, does not apply to the transition costs recoverable under Order No. 636, which will be incurred as a result of the options granted to pipelines' customers and the improved quality of transportation services required under the provisions of that order.

h. Sunset date for GSR costs and Order No. 528 costs

The Illinois Commerce Commission urges the establishment of a sunset date on GSR cost recovery mechanisms because, it argues, as long as pipelines have the right to retroactively bill customers for these costs, they will be in a preferred position relative to other merchants.

While the Commission in Order No. 636 did not impose a sunset date for making filings to recover GSR costs, it encouraged parties to the restructuring proceedings to establish such dates on a case-by-case basis. Furthermore, the Commission indicated its intention to audit each pipeline's gas supply contracts three years after the effective date of the final

rule, to ensure the pipeline's diligent realignment efforts, unless the pipeline had agreed to a sunset date in the interim.[491] The availability of Order No. 636 surcharges on transportation to recover GSR costs is also limited, as noted earlier, to those costs attributable to customers' decisions during restructuring.

Tejas claims that the Commission has apparently determined that, at some future date, the types of costs recoverable under Order No. 528 will become Order No. 636 transition costs, in effect establishing a sunset date for Order No. 528, and argues that the Commission was arbitrary and capricious in establishing such a sunset date *sub silentio*. Tejas urges the Commission to establish a rebuttable presumption that all GSR costs are appropriate for recovery under Order No. 528, rather than under Order No. 636, unless the pipeline proves otherwise by a preponderance of the evidence.

Tejas misunderstands Order No. 636 on this issue. Order No. 528 costs cannot "become" Order No. 636 costs. Furthermore, the Commission has not established a sunset date for filing to recover costs under Order No. 528. Until a pipeline is in full compliance with Order No. 636, it will recover its buyout and buydown costs under Order No. 528.

i. Firm transportation at fixed rates, discounts, and subject to caps

Tejas also objects to imposing demand surcharges on firm

491. Order No. 636 at p. 30,459, n. 286. The Commission will clarify, as requested by Texas Gas Transmission Corporation, that the Commission audit of a pipeline's recovery of its GSR costs can be avoided if the pipeline and its customers agree to a sunset date for filing for recovery of such costs within three years of the effective date of the pipeline's compliance filing, rather than from the effective date of Order No. 636 itself.

transportation customers that are not former sales customers. Tejas points out that, under Order Nos. 500 and 528, such customers were liable for volumetric surcharges, but not fixed charges. Under that policy, pipelines have agreed to provide firm transportation at fixed rates, and Tejas argues that the imposition of demand surcharges undermines the economics of those arrangements.

Firm transportation customers under a pipeline's Part 284 blanket certificate who pay more for firm transportation service enjoy the increased flexibility and reliability of the restructured firm service, plus the ability to release capacity more easily and efficiently, whether or not they have ever been sales customers of the pipeline. If a pipeline agreed to provide transportation service at a fixed rate, without a right to passthrough any surcharges or other cost increases, then the pipeline will have to bear the costs of the bargain it made.

Natural asserts that it sometimes has to discount reservation fees and therefore should be permitted to reflect an adjustment for costs which are not recovered due to discounting and to extend the recovery period. ANR asks for authority to direct bill some of its GSR costs, because it has negotiated rate caps with certain firm transportation customers that will preclude recovery of a demand surcharge.

The Commission will not relieve the pipeline of the consequences of the agreements it entered into to provide firm service at a discount or to bear the risk of increased costs for such service by permitting it to shift transition costs to other customers.

j. LDCs that buy gas from producers whose contracts they have paid to realign

The Pennsylvania PUC argues that it is inequitable to require LDCs to pay for the contract reformation costs incurred for gas not taken and then require them to go out and buy the same gas directly from the producer.

Customers will not be required to take assignments of gas supply contracts from producers, under Order No. 636. LDCs will have the option to purchase gas directly from producers or continue purchasing from the pipeline, whichever they determine is in their best interests. It is not inequitable for LDCs to pay for some portion of the pipeline's cost of reforming its supply contracts, since they will realize the benefit from the availability of market-sensitive gas prices under the reformed contracts if they continue purchasing from the pipeline, or even if they do not, because of the effects on competition of prices under the pipeline's reformed contracts.

k. Stranded costs

The Iowa, Missouri, and Wisconsin Commissions seek clarification that just because a cost fits Order No. 636's definition of a "stranded cost" does not mean that it was prudently incurred. Recovery of such costs should be disallowed, they argue, if they are the product of mismanagement, neglect, imprudence, or the like. The Commission grants this requested clarification.

The NASUCA argues that stranded investment costs are costs associated with physical plant that is no longer used and useful and should therefore no longer be includable in the rate

base. On the other hand, Williams seeks clarification that the cost of abandoning certain facilities that will no longer be needed for rendering its restructured services as a result of the capacity reallocation process will be fully recoverable as stranded costs.

LILCO asserts that creative pipelines will have opportunities to abuse Order No. 636's authorization to recover "stranded costs." For example, they can rid themselves of unused gathering facilities in declining production areas, underutilized upstream capacity, and capitalized lease payments on properties held for future development. LILCO asks the Commission to impose a strict eligibility test on stranded costs to preclude recovery of such costs.

Columbia asserts that some pipeline gathering and lateral facilities, and perhaps some products extraction facilities, will no longer be fully subscribed after restructuring, and requests the Commission to declare that the costs of such facilities may be recovered as stranded costs under Order No. 636. Columbia also seeks clarification that the costs of liquidating its system supply storage inventory will be recoverable as transition costs.

In Order No. 636, the Commission said that pipelines had to file to recover stranded costs in a general rate case. The Commission will consider arguments about whether particular facilities are used and useful, or whether the costs should be recoverable as transition costs, in the cases where the issues arise.

l. Excess royalty reimbursement clauses

The Minerals Management Service of the Department of the Interior (MMS) requests that pipelines be allowed to recover as GSR costs under Order No. 636 the costs that arise from

their contingent liability under earlier agreed to excess royalty reimbursement clauses. MMS says that it has decided to continue its past practice of requiring royalties to be paid on gross proceeds accruing to the producer from production, and that lessees have paid, and MMS has billed, and will bill, lessees of Federal and Indian lands for those portions of the take-or-pay settlement payments by pipelines that accrue to past or future production. Where pipelines included contingent excess royalty reimbursement clauses in their take-or-pay settlements with producers from such leases, they will be liable to reimburse the producers for such excess royalty payments. MMS is concerned that pipelines that have to make such payments to producers under their take-or-pay settlements may not be able to recover them under the provisions of Order No. 528 because of a December 31, 1990 sunset date, and urges the Commission to correct this apparent oversight by permitting recovery of such costs under the mechanism for Order No. 636 GSR costs.

As discussed above, there is no sunset date under Order No. 528. In addition, whether these costs are attributable to Order No. 636 restructuring will be decided on an individual pipeline basis.

m. Transition cost recovery from direct sales customers

The Industrial Gas Users Conference seeks clarification that the Commission may not require the imposition of transition costs under Order No. 636 on direct sales customers of a pipeline, because the Commission has no power to set direct sales rates.

Although the Commission lacks jurisdiction over direct sales of natural gas, it has jurisdiction over the transportation

component of direct sales,[492] and exercised that authority in Order No. 636 to require the embedded transportation service to be unbundled from the direct sales service.[493] Thus, transportation of direct sales gas from the unbundling point on pipelines with Part 284 blanket transportation certificates will necessarily be under the authority of that certificate and subject to the Commission's jurisdiction over Part 284 transportation rates.[494] Therefore, transition costs recoverable through surcharges on Part 284 transportation rates will be collectible from direct sales customers that use the pipeline's open access transportation service, like any other shipper.

n. Amortization period for recovery of GSR costs

The Fuel Managers Association requests the Commission to require pipelines to permit their firm transportation customers to extend their transition cost amortization period for at least fifteen years, subject to liability for the carrying costs. According to the Fuel Managers Association, such an extended amortization period will be very important to cogenerators and independent power producers who entered into long-term transportation contracts at fixed rates without anticipating a demand surcharge for GSR costs.

The Commission will not specify a minimum or maximum period for a pipeline to amortize the collection of its GSR costs,

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492. Mississippi River Transmission Corp. v. FERC, No. 91-1164 (D.C. Cir. July 21, 1992).

493. See the discussion of the Commission's legal authority over direct sales at III.A.3, and the clarification of the impact of Order No. 636 on direct sales at V.D.3.

494. *See* United Gas Pipe Line Company, 50 FERC ¶ 61,268 (1990).

but will leave that as a matter that must be resolved on a case-by-case basis. However, the Commission strongly encourages the parties to use a shorter-term amortization, such as a thirty-six month period, in order not to prolong the transition.

o. Bankrupt firm shippers and project-financed pipelines

Ozark Gas Transmission System (Ozark) wants a declaration that if the Commission rejects its other requests concerning existing shipper liability for released capacity, the Commission will permit the costs resulting from Ozark being declared in default of its indenture as a recoverable transition costs. Ozark asserts that the Commission must also address the situation where a firm shipper rejects its T-1 service agreement in a bankruptcy because it no longer needs the capacity as a result of Order No. 636, and Ozark is unable to collect the full amount of the minimum bill through that proceeding.

The Commission is granting the clarification requested by Ozark concerning releasing shippers' liability on project financed pipelines, as discussed below, thus alleviating Ozark's concern about default on its indenture. The question concerning a shipper in bankruptcy rejecting a service agreement can be dealt with when and if it arises in a proceeding.

p. Maximum bid to exclude demand surcharges

NGSA argues that firm customers should not be allowed to evade their responsibility for demand surcharges through the capacity reassignment process, and asks the Commission to expressly state that for purposes of capacity reassignment, the maximum bid shall not include the assignor's realignment surcharge.

NGSA's request is denied. For purposes of capacity reassignment, the maximum bid includes the assignor's realignment charge.

q. Downstream customers' liability for upstream pipelines' transition costs and capacity

LILCO requests the Commission to require a downstream pipeline's share of an upstream pipeline's transportation and transition costs to be allocated to downstream customers in proportion to their contract demand sales entitlement on the downstream pipeline. Furthermore, downstream customers choosing not to take the upstream capacity should be required to pay the net present value of their allocable share in the form of an exit fee.

The Commission will address this issue when it arises in individual pipeline restructuring proceedings.

r. Surcharge to recover new facilities costs

Questar asks that pipelines be permitted to implement a surcharge based on a balancing account to recover new facilities costs, because most of these costs will be incurred early in the restructuring process and pipelines should not have to defer recovery until they need to file a general rate case.

Pipelines should seek to recover the costs of new facilities necessary to implement restructuring in a general rate case as soon as they need to. The Commission will not adopt a special mechanism for the recovery of new facilities costs and will deny Questar's request.

s. Liability of pipeline under assigned gas supply contract

Marathon requests clarification that when a pipeline makes an assignment of a gas supply contract to one of its customers, the pipeline will remain liable on the contract unless the producer releases the pipeline.

Whether a pipeline remains liable to a producer under an assigned gas supply contract depends on the terms of the contract. The Commission's encouragement to pipelines to assign their gas supply contracts would not affect those terms.

C. Schedule and Procedures

1. Notice to all customers

The APGA requests rehearing of the requirement of Order No. 636 that all LDCs must participate in their pipeline supplier's restructuring proceedings or risk loss of their contracted-for capacity rights. APGA asserts that small publicly owned LDCs generally do not intervene and participate in Commission proceedings. APGA also states that many of the small LDCs will not receive actual notice of the pendency of their pipeline supplier's restructuring proceedings through publication of notice in the *Federal Register*. APGA urges the Commission to require pipelines to serve all of their customers with copies of the Commission's notice of its new restructuring proceedings, along with a clearly drafted letter explaining the extraordinary nature of these proceedings and the capacity rights that will be at stake. Furthermore, APGA requests that small customers be afforded leave to intervene out of time to protect their rights after they receive actual notice of the restructuring proceedings.

Appendix C

Under section 284.214(c), pipelines subject to Order No. 636 were required to initiate discussions by June 8, 1992, concerning restructuring, with *all* of their customers and other interested parties that had intervened in the restructuring proceedings. On May 22, 1992, the Secretary of the Commission issued a Notice of Procedures in all restructuring proceedings advising pipelines of their obligation under Rule 2010 of the Commission's rules of practice and procedure to serve a copy of their compliance filings on each person whose name is on the official service list, and any other person required to be served under law, or Commission rule or order. The Commission will clarify that a pipeline must serve a copy of its compliance filing in its restructuring proceeding on *all* of its customers, and the state regulatory commissions that regulate its customers, whether or not they have intervened in that proceeding.[495]

In Order No. 636, the Commission strongly encouraged interested parties to intervene and participate in restructuring proceedings before pipelines file their compliance filings, and indicated that motions to intervene after those filings are made would be viewed with disfavor. Publication of notice of the institution of the restructuring proceedings in the *Federal Register* constitutes sufficient notice to any interested party. Lack of actual notice of the proceedings will not be sufficient grounds for granting late interventions.

2. Extend the procedural schedule

APGA asserts that the truncated procedural timetable for

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495. *See* 18 CFR §§ 154.16 (Posting) and 154.22 (Notice requirements). This clarification is also responsive to the concerns raised by the Ohio Consumers' Counsel in its request for reconsideration of the May 22, 1992 notice.

implementing Order No. 636 will overwhelm the resources of all segments of the natural gas industry. Many parties will have to participate in restructuring proceedings on several pipelines simultaneously, and APGA asserts that it is not realistic to expect that this can be done well by the end of the year. The brief period for discussions between the pipeline's deadline for serving its implementation plan summary on July 7, 1992, and the deadlines for making compliance filings is the most troubling, according to APGA. Furthermore, APGA argues, the Commission has not allowed itself sufficient time for reviewing, analyzing, and approving or rejecting the compliance filings in time for the 1993-1994 winter heating season. According to the APGA, since the "no-notice" service on that LDCs will have to rely on to guarantee peak-day service to their customers is a new idea, yet to be fleshed out, the inadequate implementation schedule poses a threat to service reliability.

Cincinnati Gas argues that because of the intensely compressed implementation schedule dictated by Order No. 636, LDCs will be effectively deprived of the ability to make informed choices about their gas purchasing decisions, or take advantage of all opportunities for long-term sales contracts in a competitive market — one of the main rationales for mandating restructuring. According to Cincinnati Gas, negotiations with producers and marketers also take considerable time, even when very few LDCs are seeking similar arrangements, and the truncated schedule for implementing Order No. 636 will prompt LDCs to turn to the pipeline for merchant service, thus thwarting the underlying purpose of the order.[496] APGA and Cincinnati Gas both urge the

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496. Cincinnati Gas also expresses particular concern about having to begin negotiations regarding restructuring of the Columbia's system, while Columbia's bankruptcy is pending. The Commission has recently denied a motion by Columbia (supported by Cincinnati Gas) for an extension of its

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Commission to extend the implementation schedule by at least twelve months.

The Industrial Groups urge the Commission to show more flexibility in implementing the restructuring program, and not to allow pipelines to force their restructuring plans upon unwilling parties to the restructuring proceedings, nor shirk its responsibility to protect the public from unreasonable terms and conditions of service. The Industrial Groups are concerned that unless parties are given reasonable extensions of time to achieve true settlements, pipelines may submit unilateral or minority settlements and leave it to the Commission to sort out the disputes. Tenneco asserts that the changes mandated in Order No. 636 are revolutionary in concept, and parties will need a considerable amount of time to decide on their positions with respect to the issues before they can come to the bargaining table.

After extended public input for over one year, Order No. 636 established certain deadlines for pipelines to initiate the process of implementing that order and stated its intention that pipelines complete the process in time for the 1993-1994 winter heating season. The Commission established deadlines from October 1, 1992 until December 31, 1992, for pipelines to make compliance filings, and expressed its view and expectation that pipelines and interested parties would achieve a consensus on most features of the restructuring filings before they are filed. The Commission also stated that it respects the rights of pipelines and interested parties to differ over how the provisions of Order No. 636 should best be implemented, and would establish

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deadline for making Order No. 636 compliance filings. Columbia Gas Transmission Corp., 60 FERC ¶ 61,047 (1992).

procedures to achieve expeditious resolution of any contested issues. Pipelines are required to propose effective dates for the *pro forma* tariff sheets they submit with their compliance filings, but the Commission will determine the effective dates of the tariffs in those filings on a case-by-case basis.

None of the requests for rehearing has presented any compelling reasons for an across-the-board postponement of the deadlines for pipelines making their compliance filings. And it is far too early for the Commission to determine whether there will be good reasons for delaying full implementation of Order No. 636 on a particular pipeline system beyond the 1993-1994 winter heating season. The transition required under Order No. 636 should be made by the entire pipeline industry in tandem, or as close in time as possible. In order to implement Order No. 636 successfully, all segments of the industry, and the Commission and its staff, will need to concentrate on the essential requirements of restructuring. Based on indications of activity in the restructuring proceedings so far, the Commission is confident that the natural gas industry can successfully concentrate its efforts in this regard, and that most pipelines, if not all, will be able to implement their restructured services within the time frame established by the final rule.

3. Implementing rate design changes under NGA Section 5

The Wisconsin Distributor Group argues that the Commission does not have authority to order pipelines to increase their rates in their restructuring compliance filings to implement the SFV rate design method. They argue that Section 5(a) of the Natural Gas Act prohibits the Commission from ordering an increase in any rate in a currently effective schedule, unless in accordance with a new schedule filed by the utility

under the provisions of Section 4 of the NGA.[497] Furthermore, they argue, a filing to implement SFV should be a major rate case under Section 4, requiring a full cost of service study, because implementation of SFV will affect substantially all of the jurisdictional rates, and will affect the pipeline's risk and various other assumptions underlying its current rates.

In Order No. 636, the Commission stated that where changes in rate design result in rate increases in certain components of the rates, or to certain customers or customer classes, even though they do not result in any overall increase in revenues, it would permit the increases in the compliance filing because it is related to a Commission directed modification in the pipeline's rate structure,[498] citing *ANR Pipeline Co. v. FERC*[499] as support for this authority. APGA argues that the *ANR* case does not support such authority, noting that the proceeding involved in that case, in which ANR was entitled to certain rate increases in connection with implementing an MFV rate design and eliminating its minimum bill, was initiated by the pipeline under Section 4.

In fact, that proceeding began with ANR's filing to implement a rate decrease under Section 4, but not to change its rate design. The Commission set the matter for hearing under both Section 4 and Section 5 of the NGA, which is its standard procedure, and ultimately made findings under the authority of Section 5 that ANR's rate design was unjust and unreasonable. ANR was ordered to revise its rates to implement the MFV rate

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497. Atlanta Gas presents similar arguments.

498. Order No. 636 at p. 30,465.

499. 863 F.2d 959 (D.C. Cir. 1988)

design method and to remove its minimum bill prospectively. When ANR made its compliance filing pursuant to the Commission's findings and order, it submitted an increased fixed-cost commodity charge to reflect the fact that with its minimum bill removed, the test period volumes for which it could bill would be fewer than the billable volumes under the minimum bill. Since ANR would no longer be recovering the minimum bill from one of its largest sales customers from which it collected a minimum bill during the test period, but which did not actually take all the volumes it had paid for under the minimum bill, ANR argued that it was entitled to a higher fixed-cost commodity charge in order to continue to recover all of its costs allocable to that charge from fewer billable volumes.

The Commission rejected ANR's increased commodity charge on the grounds that it was not authorized by the Commission's order requiring removal of the minimum bill and would violate the filed rate doctrine. The Commission further noted that ANR could file for a rate increase to reflect the reduced volumes under NGA Section 4.[500] The court of appeals reversed, concluding that the Commission had not rationally explained why its requirement that ANR's minimum bill had to be removed would not authorize the removal of volumes attributable to the minimum bill for purposes of calculating the amount of the fixed-cost commodity charge. In its order on remand, the Commission acknowledged its subsequent recognition of the principle that rate design revisions that require reductions in one component of a pipeline's rates will usually require simultaneous increases in some other component in order for the pipeline to recover its cost of service.[501] On remand, the

500. ANR Pipeline Company, 40 FERC ¶ 61,067 at pp. 61,204-5 (1987).

501. ANR Pipeline Company, 48 FERC ¶ 61,004 (1989), *citing* Tennessee Gas Pipeline Company, 46 FERC ¶ 61,113 at p. 61,443 (1989).

Commission conceded that ANR should have been entitled to reduce its design volumes and increase its fixed-cost commodity charge to compensate for its loss of revenue from the elimination of its minimum bill, and indicated that, but for the provisions of an intervening settlement, ANR would have been authorized to impose a retroactive surcharge to recover that revenue.[502]

Thus *ANR* stands for the proposition that when the Commission orders a pipeline to implement a different rate design method that requires reductions in one component of the pipeline's rates, it must permit the pipeline to implement offsetting increases in some other component simultaneously in order for the pipeline to recover its cost of service, unless there are good reasons for prohibiting the simultaneous increases and requiring the pipeline to implement the needed increases in a separate Section 4 proceeding.

The Commission does not see any good reason for generally prohibiting pipelines from implementing simultaneously the decreases and offsetting increases in rates necessary to effectuate the just and reasonable rate designs required under Order No. 636. The Commission in Order No. 636 specifically required the pipelines to design their rates using the cost of service and total throughput on which their rates in effect on the date of the compliance filing are based. Thus, the Commission is not ordering, but is rather prohibiting, any revenue increases to the pipeline. In ordering pipelines to file *pro forma* tariff sheets indicating how they propose to implement the requirements of Order No. 636, the Commission is not ordering any increase in rates. When the Commission concludes that a pipeline's tariff sheets and schedules are in compliance with Order No. 636, the Commission will generally exercise its discretion to *permit*, but

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502. 48 FERC ¶ 61,004 at pp. 60,010-11 (1989).

not *order*, the pipeline to implement any offsetting increases in rates, or components of rates, simultaneously with the necessary rate decreases, in accordance with the new tariffs and schedules filed by that pipeline. This procedure accords with the plain meaning of Section 5, established Commission practice, common sense, and court decisions on the issue.

4. Concurrent consideration of Section 4 filing for transition costs

INGAA argues that a mechanism for recovery of transition costs needs to be finalized in conjunction with the restructuring proceeding, preferably through a special rate filing, rather than a full blown Section 4 rate case. In INGAA's opinion, the final transition cost recovery mechanism developed in the rate proceeding should be part of the restructuring proceedings, and the Commission should not approve the compliance filing or settlement until the transition cost recovery mechanism is ready for implementation. K N Energy also suggests pipelines and their customers should be given an opportunity to reach a satisfactory resolution of the transition costs issues in the context of negotiated settlements in each pipeline's restructuring proceeding, and objects to the requirement that certain transition costs may only be recovered by filing a general rate case under Section 4 of the NGA. Southern also argues for concurrent resolution of transition cost recovery issues with all other restructuring issues because customers will not be able to make informed choices about service options until they know the transition costs that will flow from those choices.[503]

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503. Northern Indiana requests the Commission not to permit transition costs to be recovered under section 4 filings, so that recovery of such costs can be deferred until the Commission has determined they are just and reasonable.

Appendix C

CIG asserts that under Order No. 636, pipelines will begin incurring transition costs essentially immediately, and will face immediate and tremendous revenue losses unless they can modify their rates to recover these costs. CIG urges the Commission to allow pipelines to file rates to recover their transition costs to become effective at the same time it accepts the pipelines' compliance tariff filings in their restructuring proceedings.

There are no insurmountable problems raised in these requests for rehearing, but also no simple answers. Pipelines are required to file their estimates of Order No. 636 transition costs and their proposals for recovery mechanisms as part of their compliance filings in the restructuring proceedings.[504] The mechanisms for recovering transition costs will be resolved in the restructuring proceedings, but the amounts to be recovered through those mechanisms will not.

Sales customers are permitted to reduce or terminate their sales entitlements during the restructuring proceedings, as well as release unneeded firm capacity if there is demand for it from other shippers, and to decide which of the pipeline's unbundled services they want, and what levels of service. The customers' choices will affect the pipeline's transition costs, and the estimated charges to recover transition costs will affect the customers' choices. Thus, the Commission recognized in Order No. 636 that the restructuring proceedings would necessarily be an iterative process.[505] Pipelines will have to realign their

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504. 18 CFR 284.14(b)(3)(iii). The amount of transition costs a pipeline may file to recover will not be limited by the amount of such costs it *estimates* in accordance with this section. (See CNG's request for rehearing.)

505. Order No. 636 at p. 30,455.

gas supply contracts in view of their sales customers' final choices and will be entitled to recover their prudently incurred costs of realignment pursuant to separate Section 4 rate filings. And pipelines may not begin collecting transition costs until after they are in full compliance with Order No. 636. The Commission will consider proposals by pipelines to initiate such recovery on a timely basis when such compliance is achieved.[506]

ANR seeks clarification that GSR costs may be recovered through *limited* Section 4 rate filings, and that such filings will not be suspended for more than one day, consistent with the Commission's practice for take-or-pay filings under Order Nos. 500 and 528. CNG also seeks to be able to file to recover *all* transition costs in a limited Section 4 filing at the time of restructuring or whenever they arise. CNG asserts that pipelines will be under extreme pressure to settle prudence challenges and will be forced to make substantial concessions or engage in costly litigation for the mere possibility of recovering their transition costs. Furthermore, CNG asserts that conditioning the possibility of transition cost recovery on full compliance with Order No. 636 will ensure protracted litigation initiated by consumers who will have virtually no incentive to resolve the dispute through settlement.

Carnegie asserts that it is unlikely to be able to recover 100 percent of its transition costs because only after it has fully implemented Order No. 636 will it be able to file to recover those costs. However, at that point, Carnegie asserts, its customers will have secured all the alleged benefits and will be in a position to challenge all transition costs without fear of losing any of the benefits. Tenneco requests the Commission to

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506. As discussed above, pipelines may file to recover GSR costs under the terms of Order No. 528.

establish streamlined procedures for challenges to prudence of GSR costs. Otherwise, they argue, the Commission will become mired in endless hearings on this issue.

CNG LDCs are concerned that the procedural schedule will not permit adequate time for consideration of challenges to a pipeline's prudence in incurring transition costs. CNG LDCs urge the Commission to follow a careful, case-by-case approach to the review of and subsequent implementation of the recovery of transition costs, even if it means going beyond the pipeline's Order No. 636 compliance filing date.

The Commission clarifies that pipelines may make limited Section 4 filings to recover GSR costs.[507] Ordinarily, such filings will be permitted to become effective after a minimum suspension. Long-term suspensions of collection under such filings would not benefit consumers because it would merely postpone the beginning of the amortization period for a fixed amount of recoverable costs, with interest accruable on balances until paid.[508] The Commission does not intend for customers to have to forego legitimate challenges to a pipeline's prudence in order to secure the benefits of restructuring. The possibility of such challenges constitute an important incentive for pipelines to negotiate vigorously to minimize their transition costs. Proceedings on prudence challenges are not constrained by any of the procedural deadlines of Order No. 636.

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507. Pipelines may also file to direct bill unrecovered balances in Account No. 191 in a limited Section 4 filing. Filing to recover stranded costs and new facilities costs must be made in the context of a general rate case. However, the Commission reiterates that there can be no recovery of transition costs until after the pipeline has fully complied with all the requirements of Order No. 636.

508. *See* Trunkline LNG Company *et al.* 59 FERC ¶ 61,342 (1992).

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The Commission expects to develop standards for evaluating pipelines' prudence in restructuring, and will be amenable to proposals for expediting final rulings on challenges to prudence.

Northern Illinois Gas urges the Commission to require each pipeline to file a new general rate case within a fixed period after restructuring in order to ensure that costs and throughput are adjusted to reflect the new services provided. It also argues that, irrespective of any refiling requirement, it is essential that pipeline rates be continuously adjusted to reflect assigned Account No. 858 and storage capacity, the impact on cost-of-service of other transition steps, the allocation of costs to the deregulated pipeline merchant function, and other changes in inputs and outputs produced by Order No. 636 compliance.

The statutory provisions of Section 4 and 5 of the NGA and the Commission's regulations are adequate to provide pipelines, as well as interested parties or the Commission, opportunities to initiate rate changes in contemporaneously with restructuring proceedings whenever anyone deems it necessary.

5. Using current cost of service and throughput for compliance filings

Cincinnati Gas asserts that after the restructuring proceedings, the pipelines' costs are likely to be significantly altered, depending on the disposition of such assets as upstream pipeline capacity, storage capacity, gas supply related costs and other factors. Furthermore, their mix of services and, necessarily, their throughput will bear little resemblance to their current throughput. Cincinnati Gas concludes, therefore, that requiring pipelines to base their rates for the restructured services on their current cost of service and throughput levels is completely illogical.

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The filings in restructuring proceedings are compliance filings to implement the Commission's rulings under NGA Section 5. The requirement that the restructuring filings must be based on the pipeline's currently approved cost of service and throughput provides assurance that the compliance filings reflect only the restructuring required by Order No. 636, and not rate or revenue changes that are not required by the rule. However, as the Commission said in Order No. 636, pipelines may file notices of rate changes under Section 4 of the NGA concurrently with their restructuring filings to reflect changes in costs or throughput, or to seek rate increases due to implementation of the rule, so long as they are not filed in the restructuring proceedings.

6. Incentive regulation

A number of parties requested rehearing with respect to incentive ratemaking. Based upon the Commission's statement "that incentive ratemaking may be a better vehicle than exposure to risk for enhancing pipeline efficiency with respect to transportation costs,"[509] the parties mentioned below assert that the issues of SFV rate design and incentive ratemaking are linked and must be considered together. Certain parties (*e.g.*, AGD, ConEd, NIEP, and Peoples Natural Gas) argue that SFV and incentive ratemaking should be considered together in separate proceedings. Certain other parties (Brooklyn Union and the New York PSC) argue that a pipeline should not be allowed to implement SFV unless it also implements an incentive rate program.

On the other hand, several parties (APGA, Illinois Commerce Commission, Marathon, Natural Gas Clearinghouse,

509. Order No. 636 at p. 30,436.

Phillips, United Distribution Companies, and UGI) argue that incentive ratemaking proposals should not be part of the restructuring proceedings. They maintain that the proceedings will be difficult enough without the implementation of incentive ratemaking as an issue and that the inclusion of this issue will divert attention from the implementation of the requirements of Order No. 636. The parties are also concerned that incentive ratemaking proposals could be used as a bargaining chip by a pipeline to the detriment of its customers.

In Order No. 636, the Commission recognized that:

> pipelines may want to utilize incentive ratemaking proposals as a competitive tool in the restructuring proceedings. Subject to the Commission's action in the final policy statement on incentive regulation, the pipelines may wish to file an incentive rate proposal along with its restructuring compliance filing. Any such incentive ratemaking proposal filed contemporaneously with the restructuring compliance filing should include sufficient detail to demonstrate the effect of the incentive rates on the straight fixed-variable (SFV) and unbundling objectives discussed above. Additionally, any incentive rate proposal must have the full support of the parties to the restructuring proceedings and be consistent with the Commission's final policy statement. (footnote omitted)[510]

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510. Order No. 636 at pp. 30,466-67.

The Commission will not, however, mandate the use of an incentive ratemaking mechanism in conjunction with SFV as requested by Brooklyn Union and the New York PSC because it is not necessary to consider SFV and incentive ratemaking together. While the change to SFV may have some impact on a pipeline's risk, and incentive ratemaking may be a way of encouraging efficiency other than exposure to risk, the Commission found in Order No. 636 that "SFV is but one aspect of risk analysis" and that the appropriate forum for risk analysis is a rate proceeding where all factors affecting risk are examined and the rate of return on equity is established.[511]

7. Triennial rate review

A number of LDCs (*e.g.*, Con Ed, AGD, Illinois Power, Michigan Gas, APGA) and state agencies (*e.g.*, New York PSC, State of Louisiana), and NASUCA argue that pipelines should continue to be subject to the three-year rate review currently required by section 154.303(e) of the Commission's PGA (purchased gas adjustment) regulations.[512] They assert that the Commission did not give any reason for eliminating the requirement. They maintain that since the pipelines still retain monopoly power over the transportation system, a three-year rate review is essential to ensure that a pipeline's transportation, storage and other non-gas rates continue to be just and reasonable.

The Commission will not require pipelines to be subject to a three-year rate review. Under Section 4 of the NGA, the Commission is required to ensure that rate changes filed by a

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511. Order No. 636 at p. 30,437.

512. 18 CFR 154.303(e).

pipeline are just and reasonable. Under Section 5 of the NGA, if the Commission finds a rate to be unjust and unreasonable, after a hearing initiated upon complaint or its own motion, it must set the just and reasonable rate. Thus, the Commission examines the justness and reasonableness of rates under these two scenarios. The three-year review was part of the PGA regulatory scheme — in exchange for the ability to change only one cost element pipelines had to agree to a reexamination of all their costs and rates at three year intervals to assure that gas cost increases were not offset by decreases in other costs. It was not employed only because a pipeline has a monopoly. Since there is no comparable special rate adjustment mechanism here, there is no reason for the three-year review. In the Commission's view the procedures provided under NGA Sections 4 and 5, for ensuring that rates are just and reasonable, should provide sufficient protection to a pipeline's customers under ordinary circumstances.

On a different point, Llano argues that the Commission acted arbitrarily and capriciously in maintaining the three-year rate filing requirement for intrastate pipelines providing NGPA Section 311 transportation while effectively eliminating the requirement for interstate pipelines.

There may or may not be merit to Llano's arguments, but intrastate rates are beyond the scope of this proceeding.

8. Miscellaneous

a. Rates in effect subject to refund when restructuring filings are made

Gas Company of New Mexico requests clarification that if

a pipeline's rates in effect at the time the restructuring compliance filings are made are being collected subject to refund, the post-restructuring collections will also be subject to refund pending resolution of the pipeline's pending rate proceeding.

The Commission grants this clarification.

b. A "reopener" provision in an existing settlement

LILCO states that a current rate settlement between it and one of its pipeline suppliers includes a "reopener" provision that permits throughput increases resulting from restructuring. LILCO seeks clarification that by requiring that new rates be set based on the currently effective total throughput, the Commission did not intend to abrogate LILCO's rights under the settlement to seek an adjustment in transportation rates based on changes in throughput.

Since this is an issue that apparently pertains to only one settlement involving one pipeline, the Commission will not address it in this order. It may be raised in the pipeline's restructuring proceeding.

c. Discovery and procedural disputes

LILCO asserts that it is essential to have a mechanism or procedure in place for resolving disputes that may arise with respect to the exchange of necessary data or information, scheduling issues, and other problems, and recommends that each pipeline's restructuring proceeding be assigned to an administrative law judge. LILCO proposes that the compliance filing be submitted to the judge for an initial finding, after

consideration of comments, of whether it complies with Order No. 636.

Tejas asks the Commission that parties to restructuring proceedings will have full discovery rights in order to verify the appropriateness of pipelines' restructuring proposals. Tejas requests that discovery procedures be available immediately, because access to accurate and complete information will greatly facilitate the settlement process.

The Public Service Company of Colorado[513] also request the right to utilize formal discovery procedures under Rule 401 *et seq.* of the Commission's rules of practice and procedure, and that an administrative law judge be appointed to each restructuring proceeding to resolve any discovery disputes.

On June 24, 1992, the Commission issued an order in this rulemaking proceeding establishing a discovery procedure for restructuring proceedings in response to a motion by Natural Gas Clearinghouse.[514] The Commission directed its staff in the restructuring proceedings to submit data requests to the pipelines to elicit information that parties would need to evaluate restructuring proposals, and required the pipelines to serve answers to those requests on all parties to the restructuring proceeding. The Commission also directed its staff to assist in resolving informally any disputes regarding such data requests, and provided that parties could present unresolved discovery disputes to the Commission after the pipeline has filed its compliance filing. Thus, the Commission has already addressed these rehearing requests.

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513. Public Service Company of Colorado, Western Gas Supply Company, and Cheyenne Light, Fuel and Power Company

514. 59 FERC ¶ 61,351 (1992)

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d. Opportunity to develop a record

Western Resources requests that a pipeline's customers have an opportunity make a record on contested items in pipeline restructuring proposals, and suggests the Commission encourage the use of alternative dispute resolution devices and set limited issues for hearing and decision on an expedited basis when such devices are not successful in resolving the issue. Western Resources asserts that pleadings on contested issues will not always provide an adequate record, because they do not afford parties the opportunity to test the merits of other parties' arguments through discovery and cross-examination.

Marathon seeks assurance that parties will be entitled to a trial-type evidentiary proceeding on issues in restructuring proceedings that turn on disputed material facts. Specifically, Marathon questions the Commission's statement in Order No. 636 that restructuring proceedings will not be set for hearing before administrative law judges unless they are consolidated with other proceedings already pending before a judge.[515] Marathon argues that petitioners' statutory due process rights under the NGA will be violated if they are denied the right to develop a record through a trial-type hearing.

The Commission will establish appropriate procedures to resolve contested issues in restructuring proceedings. However, the Commission will not routinely set restructuring proceedings for hearing before administrative law judges. It should be possible in most such proceedings to resolve disputed issues on the basis of adequate records without trial-type hearings. But the Commission will determine whether such a hearing is necessary in a particular restructuring proceeding on the basis of the nature of the disputed issues.

515. Order No. 636 at p. 30,467.

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e. Timing of compliance filings by downstream pipelines

Tenneco asserts that it is unreasonable for the Commission to expect downstream pipelines to restructure their services when they do not know what their upstream pipelines' services will look like, and suggest that downstream pipelines have an additional six to eight months to implement their restructuring initiatives. CNG also seeks rehearing of the requirement that downstream pipelines make compliance filings contemporaneously with those of their upstream pipelines.

The Commission denies these requests. While there may be significant details to be worked out in restructuring proceedings, Order No. 636 provides very specific direction on its major features. Downstream pipelines can prepare their compliance filings with confidence that their upstream pipelines (which are subject to Order No. 636) will be required to comply with the same provisions of that order that the downstream pipelines are required to comply with. The Commission will consider any proposals by downstream pipelines to adjust certain provisions of their own restructuring filings in light of restructuring provisions implemented on their upstream pipelines as they are presented, but no basis has been shown for an across-the-board deferral of compliance by downstream pipelines.

f. Requests for exemption from Order No. 636

OkTex asks that Order No. 636 not be applied to it, because it is small (only eight miles of pipe) and provides transportation only. Various other small pipelines and ANR Storage Company (ANR Storage) also seek exemption from Order No. 636. ANR

Storage asserts that it neither sells gas, nor transports it on behalf of others, and that it does not have a blanket transportation certificate under Part 284.

Pipeline-specific requests of this nature should be raised in pleadings in the pipeline's restructuring proceedings. They will not be addressed in this order. The Commission has terminated certain restructuring proceedings on grounds that pipelines were not jurisdictional[516] or had unique characteristics that render the restructuring requirements inapplicable.[517]

g. The Commission's staff in restructuring proceedings

The Public Service Company of Colorado also requests that the Commission's staff be involved in the restructuring proceedings as an active player, and not just as a facilitator. They assert that over the years, many smaller customers of the pipelines have come to rely on the staff's active participation in Commission proceedings as a critical resource.

The Commission's staff is actively involved in restructuring proceedings and will continue to be so, as needed, throughout the course of those proceedings. However, the role of the staff in these proceedings is not the same as that of litigation staff in proceedings set for hearing before an administrative law judge. The staff involved are serving as advisory staff to the Commission are therefore subject to the *ex parte* rules. They

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516. North Penn Gas Company, 59 FERC ¶ 61,258 (1992), Inland Gas Company, Inc., 59 FERC ¶ 61,365 (1992), and Green Canyon Pipe Line Company, 59 FERC ¶ 61,371 (1992).

517. Freeport Interstate Pipeline Company, 59 FERC ¶ 61,378 (1992).

will assist the parties in understanding how to comply with Order No. 636 and will advise the Commission on whether the pipelines and interested parties are implementing Order No. 636 on a timely basis, and whether the filings submitted by the pipelines constitute effective compliance with the Final Rule.

h. Coercive settlement provisions

In Order No. 636, the Commission said it would not tolerate coercive provisions in a pipeline's offer to settle a restructuring proceeding that have the effect of forcing parties to acquiesce in a settlement by threatening the denial of essential services.[518] Marathon argues that such coercive provisions pertaining to transition cost recovery should also be proscribed, citing a decision on a "cosmic" settlement for Tennessee Gas Pipeline Company where the Commission found that transition cost recovery provisions do not pertain to essential services.[519]

As the Commission said in Order No. 636, a party may not be threatened with denial of essential services under restructuring for failure to agree to a settlement offer by the pipeline. However, if a party to a restructuring proceeding does not agree to a pipeline's offer to compromise its contested claim for transition costs, the pipeline may to file to recover the costs it claims, subject to Commission rulings on any challenge to its prudence or protests to eligibility of the costs for recovery as Order No. 636 transition costs. The availability of essential services will not be jeopardized by ongoing proceedings on contested transition cost filings.

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518. Order No. 636 at pp. 30,467-68.

519. Tennessee Gas Pipeline Company, 59 FERC ¶ 61,045 at pp. 61,171-175 (1992).

Appendix C

i. Precedential effect of rulings on restructuring proceedings

Marathon requests that the Commission state that rulings in restructuring proceedings will have no precedential effect, similar to the statement usually made in approving settlements. Otherwise, parties that have an interest in these proceedings would have to intervene in or monitor all of the restructuring proceedings to protect their interests. As an alternative, Marathon suggests that the Commission provide public notice and an opportunity for comment whenever an issue of potentially generic applicability arises in a restructuring proceeding.

Commission rulings on contested issues in restructuring proceedings will have value as precedent, just as Commission rulings on the merits in any other type of proceeding. If a ruling in one restructuring proceeding appears to affect parties in other proceedings in which the same or similar issues are pending, the affected parties are free to argue that the precedent established in another proceeding should not be applied in their case.

X. IMPACT ON PROJECT-FINANCED AND ANGTS PREBUILD PIPELINES

A. Project-financed Pipelines

Ozark objects to the provisions of the new section 284.242 of the Commission's regulations that require pipelines to offer to assign their firm capacity on upstream pipelines to their firm shippers. Because of the terms of its financing arrangement (indenture), Ozark's lenders have the right to approve any other shippers that take on the minimum bill obligations currently

borne by Columbia and Tennessee, and if either of these pipelines is relieved of its liability for its capacity on Ozark without the lenders' approval, Ozark will be in default on the terms of its loan. Thus, Ozark seeks a ruling from the Commission that section 284.242 will not work to allow Columbia or Tennessee to assign their firm capacity on Ozark to another shipper until and unless that shipper has been approved by Ozark's lenders in accordance with the terms of the indenture.[520]

A consortium of banks[521] that provided financing for Kern River, also a project-financed pipeline, seek clarification that shippers under existing firm transportation contracts will not be relieved of their contractual obligations as a result of the capacity reallocation process under Order No. 636 without the pipeline's consent.

The Commission will grant the requested clarification. Assignors of capacity on project-financed pipelines whose loan agreements require creditor approval of substitute shippers are not relieved of liability for assigned capacity, unless the project-financed pipeline agrees to release the assignor from such liability. Thus, if creditor approval of the new shipper cannot be secured, the assigning shipper must serve as a guarantor of payments under the existing contract even though another shipper is assigned the capacity.

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520. Other pipelines make this same request: Trailblazer Pipeline Company, Northern Border Pipeline Company (Northern Border), Overthrust Pipeline Company (Overthrust), U-T Offshore System (U-TOS), and Wyoming Interstate Company (Wyoming Interstate).

521. Barclays Bank, PLC, Canadian Imperial Bank of Commerce, Credit Lyonnais, and the Fuji Bank, Ltd. (Barclays).

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B. ANGTS prebuild pipelines

Foothills Pipe Lines, Ltd.(Foothills), a Canadian pipeline, urges the Commission to exempt the ANGTS prebuildproject from Order No. 636 to the extent necessary to ensure that there will be no assignment, release, or reallocation of prebuild pipeline capacity without the prior agreement of all parties to the relevant prebuild import and resale contracts. Foothills is concerned that under section 284.242 of the Commission's regulations, as promulgated in Order No. 636, Northern Natural and Panhandle Eastern Pipeline Company (Panhandle), both of whom are major purchasers of Canadian gas for transport through Northern Border, a component of the ANGTS prebuild project, could be required to assign their capacity on Northern Border to their firm customers, thus arguably excusing Northern Natural and Panhandle from purchasing Canadian gas from Northwest Alaskan Pipeline Company and, indirectly, from Pan-Alberta Gas, Ltd. (Pan-Alberta).

Foothills is also concerned that section 284.14(e) of the new regulations would permit Pacific Interstate Transmission Company an opportunity during the restructuring proceedings to relinquish its prebuild capacity on PGT, Northwest, and El Paso, and permit Pan-Alberta Gas (U.S.) to relinquish its prebuild capacity on Northern Border. Finally, Foothills notes that the capacity release program under new section 284.243 would provide buyers of prebuild gas ongoing opportunities to release their prebuild capacity to other shippers. Foothills asserts that in each of these situations, there could be a decoupling of the prebuild transportation capacity from the prebuild gas purchase obligations which, together, provide the revenues to defray the cost of the Canadian prebuild investment. The Canadian prebuild investment includes not only the Foothills

interprovincial pipeline facilities, but also intraprovincial pipeline facilities and substantial gas producing facilities. According to Foothills, permitting pipelines grounds to default on their purchase obligations to Canadian producers would violate various time-honored commitments by the Commission, the U.S.-Canadian Agreement on Principles, and Section 9(d) of the Alaska Natural Gas Transportation Act.[522] Foothills also expresses concern about the possibility that Northern Natural and Panhandle will lose needed capacity on their own systems through the unbundling and conversion process under sections 284.284 and 284.8(a)(4) of the new regulations.

Foothills' and Pan Alberta's concerns about the rule's effect on the prebuild shippers' purchase obligations are misplaced. The rule does not alter contracts between shippers and their suppliers. Moreover, nothing in the rule is intended to disturb the United States government's commitment to the ANGTS prebuild. Foothills' concern about Panhandle and Northern Natural's capacity can be addressed in those pipelines' restructuring proceedings.

XI. EFFECTIVE DATE

The amendments to the Commission's regulations adopted in this order on rehearing will become effective [insert date 30 days after publication of this order in the *Federal Register*].

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522. Pan Alberta makes very similar arguments in its request for rehearing.

Appendix C

List of subjects in 18 CFR Part 284
Continental shelf
Natural Gas
Reporting and recordkeeping requirements

In consideration of the foregoing, the Commission denies rehearing in part, grants rehearing in part, clarifies Order No. 636 as described above, and amends Part 284, Chapter I, Title 18, *Code of Federal Regulations*, as set forth below.

By the Commission. Commissioner Moler dissented in part with a separate statement attached. Commissioner Terzic concurred with a separate statement attached.

(SEAL)

Lois D. Cashell,
Secretary.

Appendix C

Part 284 — CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

1. The authority citation for Part 284 is revised to read as follows:

Authority: 15 U.S.C. 717-717w; 15 U.S.C. 3301-3432; 43 U.S.C. 1331-1356; 42 U.S.C. 7101-7352; E.O. 12009, 3 CFR, 1978 Comp., p. 142

2. In § 284.14, paragraph (b)(3)(iii) is redesignated as paragraph (b)(3)(v), new paragraphs (b)(3)(iii) and (iv) are added, and paragraph (e) is revised to read as follows:

§ 284.14 Provisions governing pipeline restructuring.

* * * * *

(b) * * *

(3) * * *

(iii) The compliance filing must include a cost-based sales rate for small customers that are entitled to purchase gas under a pipeline's one-part, imputed-load-factor rate schedule on the effective date of a pipeline's blanket certificate under § 284.284, to apply for a period of one year from that date.

(iv) (A) Except as provided in paragraph (b)(3)(iv)(B) of this section, a pipeline that offered a sales or transportation service to small customers with a one-part volumetric rate at an imputed load factor on May 18, 1992, must include tariff

provisions in its compliance filing to charge a rate for firm transportation services under § 284.8 on the same basis and under the same eligibility criteria as the small customer sales or transportation rate under the pipeline's last-approved tariff provisions for those services.

(B) A pipeline may increase the permissible daily service levels for the small customer transportation rate up to 10,000 Mcf or Dth per day. A customer that receives service under its small customer transportation rate may not ship gas under any interruptible transportation rate schedule available from the pipeline or ship gas as a replacement shipper on the pipeline under § 284.243, unless the customer has exhausted its daily levels of firm transportation from the pipeline. A pipeline's firm transportation service for small customers may not contain service conditions more restrictive than the restrictions permitted by paragraph (b)(3)(iv) of this section.

* * * * *

(e) *Adjustments to firm transportation service; automatic abandonment.* (1) Any firm shipper on a pipeline subject to this section must give notice to the pipeline during the pipeline's restructuring proceeding whether the shipper wants to retain, reduce, or terminate its contractual rights to firm transportation service.

(2) Except as provided in paragraph (e)(4) of this section, any firm shipper may reduce or terminate its contractual rights and obligations for firm transportation service subject to this section, if the shipper gives notice of its desire to reduce or terminate service under paragraph (e)(1) of this section, and

(i) the pipeline receives an offer for the available firm transportation service from a creditworthy shipper that is equal to or greater than the rate the existing firm shipper is contractually obligated to pay, up to the maximum rate, or

(ii) the pipeline agrees to the reduction or termination of the existing firm shippers' contractual obligations.

(3) Except as provided in paragraph (e)(4) of this section, a pipeline subject to this section may abandon firm transportation service under a contract with a firm shipper:

(i) to the extent the shipper reduces or terminates its contractual obligations under paragraph (e)(2) of this section, or

(ii) if, during the pipeline's restructuring proceeding, another creditworthy shipper offers a higher rate for the service than the existing firm shipper, up to the maximum rate, which the existing shipper declines to match, and the pipeline is not contractually precluded from charging the higher rate to the existing firm shipper.

(4) Paragraphs (e)(1)-(3) of this section do not apply to the firm transportation service provided for a downstream pipeline subject to Subpart B or G of this part on an upstream pipeline subject to Subpart B or G of this part, unless the existing firm customers of the downstream pipeline concur in the decision of the downstream pipeline to reduce or terminate its firm transportation service on the upstream pipeline.

(5) The authority to abandon service under this paragraph is effective:

(i) on the effective date of the contract to provide the service to another shipper, or

(ii) on the effective date of the pipeline's agreement to the reduction or termination of the existing firm shipper's contractual obligations.

3. In § 284.221, the introductory text of paragraph (d)(2) is revised by removing the words "more than one year" and adding, in their place, the words "one year or more", and paragraph (d)(2)(ii) is revised by removing the words "those terms" at the end of the paragraph and adding, in their place, the words "the terms of any such offer".

4. In § 284.242, the first sentence is revised to read as follows:

§ 284.242 ***Assignment of firm capacity on upstream pipelines.***

An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must offer without undue discrimination to assign to its firm shippers its firm transportation capacity, including contract storage, on all upstream pipelines, whether the firm capacity is authorized under Part 284 or Part 157. * * *

5. In § 284.243, paragraphs (c) and (d) are revised, and a new paragraph (h) is added, to read as follows:

§ 284.243 ***Release of firm capacity on interstate pipelines.***

* * * * *

(c) Except as provided in paragraph (h) of this section, a

firm shipper that wants to release any or all of its firm capacity must notify the pipeline of the terms and conditions under which the shipper will release its capacity. The firm shipper must also notify the pipeline of any replacement shipper designated to obtain the released capacity under the terms and conditions specified by the firm shipper.

(d) The pipeline must provide notice of offers to release or to purchase capacity, the terms and conditions of such offers, and the name of any replacement shipper designated in paragraph (b) of this section, on an electronic bulletin board, for a reasonable period.

* * * * *

(h) (1) A release of capacity by a firm shipper to a replacement shipper for any period of less than one calendar month need not comply with the notification and bidding requirements of paragraphs (c) through (e) of this section. A release under this paragraph may not exceed the maximum rate. Notice of a firm release under this paragraph must be provided on the pipeline's electronic bulletin board as soon as possible, but not later than forty-eight hours, after the release transaction commences.

(2) A firm shipper may not rollover, extend, or in any way continue a release under this paragraph without complying with the requirements of paragraphs (c) through (e) of this section, and may not re-release to the same replacement shipper under this paragraph until thirty days after the first release period has ended.

6. In § 284.282, a new paragraph (d) is added to read as follows:

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§ 284.282 *Definitions.*

* * * * *

(d) *Small customer* is a customer that purchases gas from a pipeline under the pipeline's one-part imputed load factor rate schedule on the effective date of the blanket certificate.

7. In § 284.284, a new paragraph (e) is added to read as follows:

§ 284.284 *Blanket certificates for unbundled sales services.*

* * * * *

(e) *Small customer cost-based rate.* A pipeline that provided bundled sales service to a small customer before the effective date of the blanket certificate granted in paragraph (a) of this section is required to offer a sales service to that customer at a cost-based rate for one year from the effective date of the certificate. The obligation to sell at the cost-based rate expires one year after the effective date of the certificate.

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APPENDIX

Alphabetized Listing of Requests for Rehearing of Order No. 636

Alabama Gas Corporation and
Clarke-Mobile Counties Gas District
Mississippi Valley Gas Company
Mobile Gas Service Corporation
North Carolina Natural Gas Corporation
Public Service Company of North Carolina, Inc.
Willmut Gas and Oil Company (Alabama Gas)

Alabama-Tennessee Natural Gas Company (Alabama-Tennessee)

American Paper Institute, Inc. (American Paper Institute)

American Public Gas Association (APGA)

Amoco Production Company (Amoco)

ANR Pipeline Company (Correction filed 5-13-92) (ANR)

ANR Storage Company (ANR Storage)

Arizona Electric Power Cooperative, Inc. (Arizona Electric)

Arizona Direct Customers

Arkla, Inc. (Arkla)

Associated Gas Distributors (Request for clarification filed 5-15-92) (AGD)

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Atlanta Gas Light Company and
Chattanooga Gas Company (Atlanta Gas)

Baltimore Gas and Electric Company (BG&E)

Barclays Bank, PLC and
Canadian Imperial Bank of Commerce
Credit Lyonnais
Fuji Bank, Ltd. (Barclays)

Brooklyn Union Gas Company (Brooklyn Union)

Brooklyn Union Gas Company
Consolidated Edison Company of New York, Inc.,
Public Service Electric and Gas Company (Joint Request)

Brymore Energy, Inc. (Brymore)

Carnegie Natural Gas Company (Carnegie)

Cascade Natural Gas Corporation
and Washington Water Power Company (Cascade)

Centra Gas Manitoba, Inc. (Centra Gas)

Cincinnati Gas & Electric Company
The Union Light, Heat and Power Company
Lawrenceburg Gas Company
Mountaineer Gas Company (Substitute copy with corrections filed 5-11-92) (Cincinnati Gas)

Citizen Action

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Citizens Gas and Coke Utility (Citizens Gas)

City Gas Company (City Gas)

City of Colorado Springs, Colorado (Colorado Springs)

City of Hamilton!, Ohio (Hamilton)

City of Vicksburg (Vicksburg)

CNG LDCs (East Ohio Gas Company, River Gas Company, West Ohio Gas Company Peoples Natural Gas Company, Virginia Natural Gas, Inc., and Hope Gas, Inc.)

CNG Transmission Corporation (CNG)

Coalition Against Straight Fixed Variable (Coalition)

Colorado Interstate Gas Company (CIG)

Columbia Gas Distribution Companies

Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company (Columbia)

Consolidated Edison Company of New York, Inc. (Correction filed 5-13-92) (ConEd)

Delta Pipeline Company (Delta)

Department of the Interior,
Minerals Management Service (MMS)

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Destec Energy, Inc. (Destec)

Edison Electric Institute (Edison Electric)

Elizabethtown Gas Company (Elizabethtown)

El Paso Natural Gas Company (El Paso)

Equitrans, Inc. (Equitrans)

Fertilizer Institute

Florida Power and Light Company (Florida Power)

Foothills Pipe Lines Ltd. (Foothills)

Fort Pierce Utilities Authority and
City of Vero Beach (Fort Pierce)

Fuel Managers Association

Gas Company of New Mexico

Great Lakes Gas Transmission Limited Partnership (Great Lakes)

Hadson Gas Systems, Inc. (Corrected pages filed 5-12-92) (Hadson)

High Island Offshore System (HIOS)

Illinois Commerce Commission

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Illinois Power Company and
Northern States Power Companies (Illinois Power)

Independent Petroleum Association of America and
Cooperating Associations (IPAA)

Indiana Gas Company, Inc. (Indiana Gas)

Indicated Shippers

Industrial Gas Users Conference

Industrial Groups (Process Gas Consumers Group, American Iron and Steel Institute, Georgia Industrial Group, Association of Businesses Advocating Tariff Equity, California Industrial Group, California Manufacturers Association, and California League of Food Processors)

Interstate Natural Gas Association of America (INGAA)

Kansas Corporation Commission (KCC)

Kentucky Ohio Gas Company (Kentucky Ohio)

Kern River Gas Transmission Company (Kern River)

K N Energy, Inc. (K N Energy)

Laclede Gas Company (Laclede)

Llano, Inc. (Llano)

Long Island Lighting Company (LILCO)

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Marathon Oil Company (Letter filed 5-11-92) (Marathon)

Maryland People's Counsel

Memphis Light, Gas and Water (Memphis Light)

Michigan Gas Utilities Division of
Utilicorp United Inc. (Michigan Gas)

Midcon Marketing Corporation (Midcon Marketing)

Midland Cogeneration Venture Limited Partnership (Midland Cogeneration)

Mobil Natural Gas Inc. (Mobil)

Municipal Gas Authority of Georgia

National Association of Gas Consumers

National Association of State Utility Consumers Advocates (NASUCA)

National Association of Regulatory Utility
Commissioners, Inc. (NARUC)

National Fuel Gas Supply Corporation (National Fuel)

National Independent Energy Producers (NIEP)

Natural Gas Clearinghouse

Natural Gas Pipeline Company of America (Natural)

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Natural Gas Supply Association/Indicated Producers (NGSA)

New England Gas Distributors

New England Power Company (New England Power)

New England Power Company in support of
Northeast Energy Associates, *et al.*

New Jersey Natural Gas Company (New Jersey Natural)

New York State Electric and Gas Corporation (NYSE&G)

Northeast Energy Associates and
North Jersey Energy Associates (Northeast Energy)

Northern Border Pipeline Company (Northern Border)

Northern Distributor Group

Northern Illinois Gas Company and
Peoples Gas Light and Coke Company
North Shore Gas Company (Northern Illinois Gas)

Northern Indiana Public Service Company (Northern Indiana)

Northern Natural Gas Company (Northern Natural)

Northwest Natural Gas Company (Northwest Natural)

Northwest Pipeline Corporation (Northwest)

Official Committee of Unsecured Creditors of the Columbia Gas
Transmission Corporation (Columbia Unsecured Creditors)

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OkTex Pipeline Company (OkTex)

O&R Energy, Inc. (O&R Energy)

Overthrust Pipeline Company (Overthrust)

Ozark Gas Transmission System (Ozark)

Pacific Gas and Electric Company (PG&E)

Pacific Gas Transmission Company (PGT)

Pan-Alberta Gas Ltd. (Pan Alberta)

PEC Pipeline Group (PEC Group)

Pennsylvania Public Utility Commission (Pennsylvania PUC)

Peoples Gas System, Inc. (Peoples Gas)

Peoples Natural Gas Company (Peoples Natural Gas)

Philadelphia Electric Company (Philadelphia Electric)

Phillips Petroleum Company and
Phillips Gas Marketing Company
GPM Gas Corporation (Phillips)

Potomac Electric Power Company (PEPCO)

Public Service Commission of the Commonwealth of Kentucky
(Kentucky PSC)

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Public Utilities Commission of the State of California (CPUC)

Public Service Commission of the State of New York (New York PSC)

Public Service Company of Colorado and Western Gas Supply Company Cheyenne Light, Fuel and Power Company (Public Service Company of Colorado)

Public Service Electric and Gas Company (PSE&G)

Questar Pipeline Company (Questar)

Reynolds Metal Company (Reynolds)

Rochester Gas and Electric Corporation (Rochester Gas)

South Carolina Pipeline Corporation (South Carolina Pipeline)

Southern California Edison Company (SoCal Edison)

Southern California Gas Company (SoCal Gas)

Southern Indiana Gas and Electric Company (Southern Indiana)

Southern Natural Gas Company (Southern)

Southwest Gas Corporation (Southwest Gas)

Spot Market Corporation of The State of Texas (Spot Market Corporation)

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State of Louisiana

State of Michigan and Michigan Public Service Commission (State of Michigan)

State Regulatory Commissions (Iowa, Missouri, and Wisconsin) (Iowa, Missouri and Wisconsin Commissions)

Tejas Power Corporation (Supplemental filed 5-20-92) (Tejas)

Tenneco Gas (Tenneco)

Tennessee Small General Service Customer Group
Columbia Small Customer Group (Tennessee and Columbia Small Customers)

Texas Gas Transmission Corporation (Texas Gas)

Three State Agencies (Montana Consumer Counsel, South Dakota Public Utilities Commission, and the Montana Public Service Commission) (Montana Agencies and South Dakota Commission)

Trailblazer Pipeline Company (Trailblazer)

Transcontinental Gas Pipe Line Corporation (Transco)

UGI Utilities, Inc. (UGI)

United Distribution Companies

United Gas Pipe Line Company (United)

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U-T Offshore System (UTOS)

Virginia Electric Power Company (VEPCO)

Washington Gas Light Company (Washington Gas)

Western Resources, Inc. (Western Resources)

Wisconsin Distributor Group

Wyoming-California Pipeline Company (WyCal)

Wyoming Interstate Company, Ltd. (Wyoming Interstate)

Appendix C

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM91-11-002

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-068

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

(Issued August 3, 1992)

MOLER, Commissioner, *dissenting in part*:

I am pleased that in Order No. 636-A we have adopted many changes in response to concerns about requiring straight fixed variable rate design. However, I must dissent from two aspects of the order on rehearing: the level of the transition costs allocated to interruptible customers, and the 20-year contract term "cap" for the right of first refusal.

Order No. 636-A rests on the rationale that the current regulatory climate is unworkable and results in "anticompetitive consequences for *all* segments of the industry and consumers."[1] Thus, the rule is necessary to create "a modern, viable natural gas industry specifically fashioned to the needs of *all* gas consumers and the Nation . . . ."[2] Because the rule is aimed at

1. Order No. 636-A, slip op. at 35 (emphasis added).

2. *Id.* at 2 (emphasis added).

providing benefits to *all* segments of the industry,[3] I believe that *all* segments of the industry should bear an equitable share of the transition costs that will inevitably occur as a result of this rule. Simply put, I do not believe the rule meets that test.

Some state commissions suggested a volumetric surcharge for the recovery of gas supply realignment costs.[4] I believe that adopting their suggestion would have been wiser than the "10 percent solution" adopted by the majority. That approach, a 10 percent allocation of gas supply realignment costs to interruptible customers, does not reflect the benefit that these customers are receiving from the industry restructuring. The figures show that at least half of the pipeline deliveries to market are under IT rate schedules.[5] To require these customers to now bear only 10 percent of the gas supply realignment costs (and these do not encompass all transition costs) is not equitable.[6]

I have come to the conclusion that a volumetric surcharge, with a true-up mechanism, most fairly reflects an equitable

3. *Id.* at 35, 37-38, 40-41.

4. *E.g.*, CPUC; Illinois; Iowa, Missouri and Wisconsin; State of Michigan; and New York PSC.

5. Order No. 636-A, slip op. at 30, n.41.

6. I must point out that, while the 10 percent cost allocation mechanism to IT service provides for some kind of "true-up" mechanism (Order No. 636-A at 5, n.5 and 353), the mechanism is not tied to IT service. Thus, while 10 percent of the costs could be allocated to IT service, if only 5 percent are collected (say over the next 2 years) there is nothing to prevent the pipeline from allocating the remaining 5 percent to firm service in the future. While I support a true-up mechanism to prevent absorption of costs by the pipeline, it should be tied to the service that the costs are allocated to.

sharing of the gas supply realignment costs that will result from the rule among all segments of the industry who will benefit from the rule. I realize that the volumetric surcharge somewhat undercuts the Commission's goal of lowering usage charges, but I find convincing the California Public Utilities Commission's argument that even the 75 percent volumetric surcharge presently in place under Order Nos. 500 and 528 for take-or-pay costs has resulted in only moderate customer impacts (4¢/dth for El Paso and 1¢/dth for Transwestern).[7] If my colleagues are right, most of the costs of contract reformation are behind us. Therefore, gas supply realignment costs should not approach the level of take-or-pay costs under Order Nos. 500 and 528. Thus, I believe that a 25 percent volumetric surcharge on all throughput volumes, with a true-up mechanism, best achieves the goal of spreading gas supply realignment costs among all segments of the industry.

My second problem is the majority's decision to unnecessarily hobble LDCs in exercising their right of first refusal. In Order No. 636, the Commission adopted a requirement that the existing customer match the contract term, without specifying the length of term it must match, as well as the price.[8] In Order No. 636-A, the majority has determined that a 20-year contract term is an appropriate cap on the contract term because it is the "traditional length of long-term contracts," and several recent contracts have been for 20-year terms.[9]

I cannot agree to such a blatantly anti-LDC rule. Almost all

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7. Order No. 636-A, slip op. at 351.

8. Order No. 636 at 30,449-450.

9. Order No. 636-A, slip op. at 306.

of the LDCs requested that the contract term be capped at 5 years because bidders could take capacity away from them by offering a longer contract term, thus endangering their ability to meet their service obligation. The record simply does not support a 20-year term. I believe that basing the selection of the 20-year term upon an "historical" basis is ludicrous — the entire thrust of the rule is toward the future, not the past. Finally, I find that using as precedent cases involving contracts for *new* pipeline capacity not to be compelling support for the 20-year term that *existing* capacity holders on *existing* pipelines must match.

Any generic regulation must, to a certain degree, be procrustean. Here, though, by providing that only 10 percent of the gas supply realignment costs be borne by IT customers, the majority cuts too short and by inflicting a 20-year contract term cap on the right of first refusal, the majority stretches too long. Therefore, I must dissent on these two aspects of Order 636-A.

Elizabeth Anne Moler
Commissioner

Appendix C

Docket No. RM91-11-002

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-068

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

(Issued August 3, 1992)

TERZIC, Commissioner, *concurring*:

I must concur in this extensive rehearing order. While I believe that the country needs the certainty inherent in this major and unprecedented order, I continue to believe that the ultimate success of the Order No. 636 process will depend on the level of flexibility the Commission and the staff on its behalf allow in implementation of the substantive provisions of this order. In this regard I reiterate my belief that many of the criticisms leveled at the rule should have been, and could have been, addressed by allowing for more flexibility in the rule.

While the rule adopts some flexibility with respect to historically sensitive issues, such as small customer gas sales and rates, it rigidly continues to preclude such requested options as: a minimal level of residual bundled sales service and use of rate designs other than SFV for cost allocation and billing purposes. Further, the rule attempts to decide issues that I think should be left to individual restructuring proceedings (*e.g.*, whether bids for released capacity should be capped at a given number of years), where there is superior expertise and factual

basis for a decision as to the specifics. This point comports with the rule's too rigid one-size-fits-all aspects. This I find surprising from the Commission, which should have a lesser rather than greater affinity for "command and control" type regulation, which this rule imitates in its level of detail for some treatments.

Thus, while the rule adopts what can be characterized as an opportunity for flexibility, with respect to a minuscule percentage of the industry's load, it retains inflexibility with respect to major parts of the pipeline industry's operations. The decisions here achieve a level of precision that may leave little left to negotiate in the restructuring process and may, in fact, be wrong for the particular system and its customers.

In sum, a major problem with this rehearing order and its predecessor lies not so much in the substance of the calls, but in a nagging belief that, based on the open meeting discussions and treatment of the companion orders, the 636 orders will be implemented by this Commission and its staff in a procrustean manner. I fear that there may be little room left for true negotiation in the restructuring process. If there is some room left to maneuver, I am not optimistic that this Commission will sanction the results of such negotiations, if they in any way deviate from the particular treatments contemplated and specified in the 636-A order.

I suspect that despite the nods to flexibility in the rehearing order and the rhetoric accompanying the voting process, little room exists to accommodate such things as changes in rate design and other treatments based on pipeline system operational differences and customer wishes.

I hope I am wrong. The situation can possibly be remedied

in practice, where it has not been in this document. That is why I can concur. Today's accompanying vote on the ANR settlement in Docket No. RS92-1-001 gives me cause to wonder. It should give the industry and state regulators cause to wonder too. However, dénouement of the Order No. 636 saga is a long way off. Thus, ever optimistic, I will continue to push for flexibility in implementation, keeping in mind that, flexibility in regulation, in this case, is in the public interest.

Branko Terzic
Commissioner

APPENDIX D — *PIPELINE SERVICE OBLIGATIONS AND REVISIONS TO REGULATIONS GOVERNING SELF-IMPLEMENTING TRANSPORTATION UNDER PART 284 OF THE COMMISSION'S REGULATIONS, AND REGULATION OF NATURAL GAS PIPELINES AFTER PARTIAL WELLHEAD DECONTROL*, "ORDER NO. 636-B", *ORDER ON REH'G*, 61 F.E.R.C. ¶ 61,272 (1992)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Martin L. Allday, Chairman; Charles A. Trabandt, Elizabeth Anne Moler, Jerry J. Langdon and Branko Terzic.

Docket No. RM91-11-004

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-069

Regulation of Natural Gas Pipelines) After Partial Wellhead Decontrol

I. INTRODUCTION

On August 3, 1992, the Federal Energy Regulatory Commission issued Order No. 636-A in which it denied rehearing in part, granted rehearing in part, and clarified Order No. 636.[1] Order No. 636, as modified by Order No. 636-A,

1. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the (Cont'd)

restructured the regulation of interstate natural gas pipeline services in order to create a natural gas industry which will provide all gas consumers and the Nation in the long-term with an adequate and reliable supply of clean and abundant natural gas at reasonable prices.

In Order No. 636-A, the Commission largely upheld the regulations adopted in and requirements of Order No. 636. The Commission did, however, make a number of changes to Order No. 636 in response to the rehearing and clarification requests. The Commission has received over eighty petitions for rehearing or clarification or both of Order No. 636-A.[2] The petitioners reargue issues on which rehearing was denied in Order No. 636, challenge changes made to Order No. 636 by Order No. 636-A, and raise some new issues with respect to details of various aspects of Order Nos. 636 and 636-A.

The main issues raised by petitioners are as follows. First, they argue that the Commission erred in denying shippers receiving transportation service under individual or transaction specific Natural Gas Act (NGA) section 7(c) certificates the right to release capacity under section 284.243 of the Commission's regulations and to have the same rights to flexible receipt and delivery points as Part 284 shippers. Second, petitioners oppose

(Cont'd)
Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 57 FR 13267 (April 16, 1992), III FERC Stats. & Regs. Preambles ¶ 30,939 (April 8, 1992) (Order No. 636); *order on reh'g*, Order No. 636-A, 57 FR 36128 (August 12, 1992), III FERC Stats. & Regs. Preambles ¶ 30,950 (August 3, 1992).

2. See the Appendix for a list of the parties seeking rehearing or clarification or both. Petitioners will be referred to by the abbreviations indicated in the Appendix.

the Commission's requirement that pipelines maintain their one-part volumetric rates computed at an imputed load factor to determine the transportation rates for small customers. Third, petitioners maintain that the Commission erred in requiring pipelines to adopt measures to avoid significant cost shifts that may result from the adoption of the straight fixed variable (SFV) method of cost classification, allocation, and rate design. Fourth, petitioners argue that the Commission should have used a period less than 20 years as the contract term cap that must be matched by a customer exercising its right of first refusal upon expiration of its contract. Fifth, petitioners contend that the Commission erred in requiring pipelines to recover 10 percent of their gas supply realignment costs from their Part 284 interruptible transportation service.

As discussed below, this order denies rehearing and clarifies Order Nos. 636 and 636-A. Hence, no further petitions for rehearing will be entertained and the instant rule is fully ripe for judicial review.

II. LEGAL BASIS AND RATIONALE FOR UNBUNDLING

This part addresses the rehearing requests with respect to the Commission's legal basis and rationale in adopting Order Nos. 636 and 636-A.

A. The Legal Basis

1. Natural Gas Act Authority

In Order Nos. 636 and 636-A, the Commission concluded that it had authority under NGA section 5 to alter a pipeline's contractual terms and conditions of service and that it had not

unlawfully revoked or modified any certificates of public convenience and necessity under NGA section 7. The Commission found that "section 7 cannot be read so narrowly as to permanently prevent the Commission from changing the terms and conditions under which a pipeline provides service, especially when the pipeline's obligation to serve and the LDC's entitlement under the certificate remain intact."[3]

Cincinnati Gas argues that an analysis of the individual elements of Order No. 636-A reveals that the rule does not preserve the pipelines' existing service obligation. It contends that this is so because the new combination of unbundled sales service and no-notice transportation service is not equal to the bundled, city-gate, firm sales service. Cincinnati Gas complains that, under the new combination of services, LDCs, rather than the pipelines, will be responsible for and bear the risk of supplying their gas for the no-notice transportation service. As an example, Cincinnati Gas states its concern that the pipeline and other gas suppliers will subject it to "output" agreements, under which a failure of supply service will merely reduce the contracts' take obligation. Hence, it maintains that it will not be insulated, as it is now, from the risk of obtaining gas supplies to minimize the risks associated with the loss or reduction of production from particular wells. It further contends that the concept of borrowing gas has not been shown to be a viable option for securing gas supplies for firm service. In a similar vein, Cincinnati Gas contends that the conditions attached to no-notice transportation, *e.g.*, imbalance penalties and operational flow orders, show that is inferior to bundled, city-gate, firm sales service. In addition, Cincinnati Gas maintains that a pipeline can free itself from its certificated sales service obligation by merely making an uncompetitive offer to the LDC.

3. Order No. 636-A at p. 30,530.

Appendix D

The Commission adheres to its discussion and conclusion in Order Nos. 636 and 636-A that it has acted within its authority under NGA sections 4(b) and 5 to prevent undue discrimination by altering the pipelines' contractual terms and conditions of service to remedy the unduly discriminatory and anticompetitive structure of the pipeline industry. The Commission rejects Cincinnati Gas's argument that the Commission's action does not comport with NGA section 7.[4] In short, the Commission concludes that the instant rule, in unbundling pipeline sales and transportation services, effects no abandonment of service to Cincinnati Gas or to any other pipeline customer. The Commission amplifies its discussion in Order Nos. 636 and 636-A as follows.

The Commission finds that Cincinnati Gas has presented no reasons to persuade the Commission that it will suffer any diminution in service. At the outset, the pipeline continues to be obligated to deliver gas on a no-notice basis to customers receiving no-notice delivery under bundled, city-gate, firm sales service on May 18, 1992. It is true that the Commission has changed the terms and conditions of service and thereby subjected pipeline customers to more responsibilities, duties, and risks. However, the Commission specifically found that those terms and conditions are necessary and reasonable operational mechanisms for implementing the Commission's remedies to eliminate the anticompetitive effect of the current

4. The Commission has the authority under NGA section 4(b) to prevent undue discrimination among pipeline customers. The Commission may invoke that section, as it did here (Order No. 636 at p. 30,405), to deal with discrimination between pipeline services whether or not it could invoke section 7 for that purpose. FPC v. Louisiana Power & Light Co., 406 U.S. 621, 646 (1972) ("Since § 4(b) deals with `service,' the FPC may invoke it to deal with curtailment programs, whether or not it could also invoke § 7 for that purpose.").

regulatory environment and pipeline services on all segments of the natural gas industry.

It is axiomatic that the consumer of any commodity should be responsible for its purchase and use. That is equally applicable here, where gas buyers will have meaningful access to a national and competitive wellhead gas market. Indeed, because the unbundling remedy requires that sales and transportation be provided separately shippers must take the initiative in obtaining gas and therefore bear the responsibilities and risks of obtaining supply. In addition, this shifting of risk is not unreasonable when, as fully discussed in Order No. 636, the pipelines (and ultimately consumers) were disadvantaged by maintaining gas supplies for sale at their WACOG to LDCs when the supplies were needed by the LDCs only as a peaking source supplement to other cheaper gas supply sources. Other terms and conditions of service are necessary to maintain the operational integrity of the pipeline system because the pipeline cannot sell gas at the city gate. This means that the pipeline must rely in the main on the shippers to supply the gas needed to keep the pipeline in balance and capable of making the necessary deliveries. Hence, imbalance penalties and operational flow orders are intimately connected with the pipeline's performance of its transportation service for shippers.[5]

To conclude, the Commission believes that through such measures, the no-notice transportation service will prove as reliable as the no-notice aspect of bundled, city-gate, firm sales

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5. Cincinnati Gas believes that pipelines will use operational flow orders to interrupt its supply of gas needed for no-notice transportation service. The Commission views operational flow orders as a vehicle for providing, not interrupting, no-notice service and will consider opposition to particular pipeline operational flow order mechanisms in the compliance filing orders.

service. The Commission merely suggested the concept of gas borrowing as a possible tool to aid in the cooperative effort to secure no-notice service. The Commission does not view the borrowing of gas as the only tool for ensuring no-notice service.

LDCs, such as Cincinnati Gas, should be able to negotiate gas purchase contracts with reasonable terms (such as output clauses or gas supply warranties) and prices in the competitive gas market. The mere possibility, unsupported by the rulemaking record, that pipelines will make uncompetitive offers does not invalidate the Commission's ability to act within its NGA section 5 authority. The Commission has no reason to believe that any pipeline will do that or, more importantly, even if a pipeline made such an uncompetitive offer, that any customer will be unable to find adequate, competitively priced supplies from other sources. With the expected enhanced quality of transportation brought about by Order No. 636, there is no reason to expect a diminution in service to any customer. Indeed, as noted, the Commission expects it would be as reliable. Cincinnati Gas has not contended that it, in fact, faces the prospect of a diminution in aggregate service. In fact, Cincinnati Gas now has more options from which to choose from than ever before. Cincinnati Gas complains that it, like other LDCs, is no longer insulated from the risks associated with buying gas in a competitive market. The Commission sees no harm to Cincinnati Gas from acquiring gas in a competitive market. The Commission concludes that the instant rule effects no abandonment of service to Cincinnati Gas or any other pipeline customer by unbundling pipeline sales and transportation services.

There is a possible abandonment of service in connection with the pipeline's obligation to serve under the blanket sales

certificate granted by Subpart J of Part 284. Effective on the effective date of that certificate, section 284.14(d) of the regulations provides for abandonment of pipeline sales if a gas purchaser exercises its right to reduce or terminate its right to purchase gas from a pipeline or if the purchaser refuses to pay the rate the pipeline offers for unbundled gas sales. However, this will result from the operation of the purchasers' decisions under the regulation — not from a generic section 7 finding. The Commission found these abandonment authorizations to be in the present or future public convenience or necessity as part of the transition to pipeline sales under the blanket sales certificates, because they will enable the pipelines and gas purchasers to structure their relationship in light of the market for natural gas.[6] As stated by Congress in section 202 of the Energy Policy Act of 1992: "It is the sense of the Congress that natural gas consumers and producers, and the national economy, are best served by a competitive natural gas wellhead market."[7]

2. Past Precedent

Cincinnati Gas argues that past Commission precedent indicates that the Commission must act under NGA section 7 to accomplish the proposed restructuring. It states that the Commission has required pipelines to apply for certificates under NGA section 7 in order to restructure their services and institute gas inventory charge (GIC) mechanisms[8] and to transport gas

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6. See Order No. 636 at p. 30,452-55.

7. Pub. L. No. 102-486, 106 Stat. 2776 (1992).

8. *E.g.*, Natural Gas Pipeline Co., 41 FERC ¶ 61,358 at pp. 61,972-73 (1972), Transwestern Pipeline Co., 42 FERC ¶ 61,370 at p. 62,083 (1988), and Transcontinental Gas Pipe Line Corp., 46 FERC ¶ 61,364 (1989).

to an existing shipper at new delivery points.[9] The Commission has acted consistently with the cited cases. The essential aspects of those cases were (1) the fact that the pipeline's customers had to consent to the abandonment of service linked to releasing the pipeline from its obligation to supply gas above a customer's nominated levels[10] and (2) the need to act prospectively with respect to an interrelated package of proposals.[11] Here, the Commission, by operation of the rule, is: (1) providing for abandonment of reduced or terminated customer purchase obligations (section 284.14(d)), (2) issuing each Part 284 pipeline a blanket sales certificate (under Subpart J of Part 284), and (3) acting prospectively under NGA section 5 to avoid a segmented approach. There is therefore no inconsistency with those cases.

The Commission also concludes that Cincinnati Gas's argument that the case requires a certificate to change delivery points is irrelevant. This is because the Commission did not, as a policy matter, permit flexible delivery points as a term and condition of transportation service until Order No. 636 modified that policy for Part 284 pipelines.[12]

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9. Transcontinental Gas Pipe Line Corp., 42 FERC ¶ 61,256 at p. 61,823, *reconsideration denied*, 43 FERC ¶ 61,207 (1988).

10. *E.g.*, Natural Gas Pipeline Co., 41 FERC ¶ 61,358 at pp. 81, 972-73 (1987); Transwestern Pipeline Co., 41 FERC ¶ 61,371 at p. 62,006 (1987); Transwestern Pipeline Co., 42 FERC ¶ 61,370 at p. 62,083 (1988); El Paso Natural Gas Co., 43 FERC ¶ 61,327 at p. 61,913 (1988).

11. *See* Transwestern Pipeline Co., 42 FERC ¶ 61,370 at p. 61,083 (1988), and Transcontinental Gas Pipeline Corp., 46 FERC ¶ 61,364 at p. 62,135 (1989).

12. Order No. 636 at p. 30,428-29.

B. The Rationale

Cincinnati Gas attacks in part the Commission's conclusion in Order No. 636-A that 100 percent standby transportation service within firm sales entitlements is not in the public interest.[13] The Commission reached this conclusion for several reasons. First, the pipeline would still be offering a bundled sales service and therefore would be offering a service at the city gate while other gas sellers would be offering a different service because their sales would occur at or near the production area. Second, the pipeline would have a natural incentive to favor its own sales in managing the pipeline system. This would run afoul of the Commission's intent to put all sellers on an equal footing. Third, the pipeline would have to retain the gas under contract to make the bundled sales, without appropriate compensation, even though the customer would be taking the gas only or mainly at peak. Cincinnati Gas takes issue with the third rationale at least for certain pipelines, such as Columbia Gas Transmission Corporation, which has implemented a GIC that compensates it for the costs associated with maintaining its gas supply portfolio. Cincinnati Gas maintains that Columbia is thus compensated even if its customers take gas only at peak.

The Commission believes that the first two reasons are adequate to support its conclusion that 100 percent standby transportation service is not in the public interest and therefore is not a reasonable alternative to unbundling sales from transportation. Moreover, that Columbia has a GIC, and is,

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13. Under 100 percent standby service, a firm sales customer may elect to receive 100 percent of its daily contract demand volumes as firm transportation service for the shipment of gas purchased from any gas suppliers, with the pipeline obligated to stand ready to provide sales gas at call at full contract demand levels.

therefore, compensated for maintaining gas supplies, does not alter the Commission's conclusion that the transportation embedded within the bundled firm sales service is superior to firm transportation, to the disadvantage of competing sellers. Last, as stated in Order No. 636-A, "[b]ecause the Commission is determining rules of general, prospective applicability to solve 'systemic problems of the natural gas [industry],'[14] it does not need to examine the circumstances of individual pipelines."[15]

Cincinnati Gas also argues that mandating unbundling runs counter to the Commission's goal of allowing parties to rely more on private contracts.[16] It maintains that it has renegotiated its pipeline contracts since Commission Order No. 436 was implemented, and that mandating unbundling merely destroys the balance between open access and pipeline sales that it has already achieved.

The Commission sees no inconsistency between exercising its authority to find a particular type of contract (bundled sales contract) unduly discriminatory and anticompetitive, and encouraging parties to rely more on contracts in a commercial

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14. Order No. 636-A at p. 30,541, *quoting* Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1166 (D.C. Cir. 1985).

15. Order No. 636-A at p. 30,541, *citing* Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1165-68 and Associated Gas Distributors v. FERC, 824 F.2d 981, 1008 (D. C. Cir. 1987). Cincinnati Gas also fails to appreciate that it can contract with any gas supplier — including the pipeline — for gas that can be produced on a stand ready basis. In conjunction with the LDC's transportation entitlement, the LDC can if, it chooses replicate a standby service.

16. *Citing* Order No. 636-A at p. 30,534.

environment where no one segment of the natural gas industry has an unfair advantage over other market participants owing to its control of a monopoly service. The Commission sees no reason why Cincinnati Gas cannot continue to rely on both pipeline and non-pipeline gas merchants in the new commercial and regulatory environment created by the instant rule.

III. UNBUNDLING — PIPELINE ACCESS TO CAPACITY

In Order No. 636, the Commission concluded that pipelines must unbundle the sales and transportation components of their bundled, city-gate, sales services. In Order No. 636-A, the Commission concluded that a pipeline cannot retain or obtain capacity downstream of the point of unbundling on its system except for storage as needed for system management and balancing and no-notice transportation purposes.

Several pipelines[17] argue that this restriction on holding on-system capacity puts them at a competitive disadvantage with their competitors because the latter can effectively rebundle by holding capacity. They add that the Commission's policy may increase the level of transition costs and is not necessary to prevent the pipelines from favoring themselves in light of the Order No. 497-type safeguards of Order Nos. 636 and 636-A. Natural and Enron argue that pipelines as merchants should be able to hold capacity on their own systems. Enron, PEC Pipeline Group, and Tenneco maintain that pipelines should be able to obtain unsubscribed firm and unutilized interruptible transportation and storage capacity once sales and transportation are unbundled.

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17. Natural, Enron (Northern Natural, Transwestern, and Florida Gas), PEC Pipeline Group, and Tenneco.

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The Commission denies rehearing and adheres to its discussion of this issue in Order No. 636-A. In brief, as stated there, the Commission believes that pipelines will be able to compete with other gas sellers for unbundled gas sales and that, "on balance any advantage on a generic basis for [pipeline] competitors [from reserving capacity for their own sales service] will be minimal and does not warrant permitting pipelines to be capacity holders and gain the opportunity to favor themselves as gas sellers in the management of pipeline transportation facilities, including storage."[18] This is especially so in the current circumstances where the pipeline must adjust from the bundled to the unbundled environment in operating the pipeline system. The Order No. 497-type safeguards imposed by Order No. 636 (standards of conduct and reporting requirements) apply only to an unbundled and not to a bundled environment. Hence, those safeguards would provide no protection against a pipeline favoring itself with its bundled sales service.

In addition, one reason for adopting the instant rule was a need to ensure equality of transportation, which the Commission continues to believe is best obtainable when the pipeline makes only unbundled sales. The pipeline differs from its competitors because of its control over a monopoly service — transportation — which its competitors must use, which gives the pipeline an inherent ability and incentive to favor its own sales service.[19] The Commission believes that it is therefore necessary to deny

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18. Order No. 636-A at p. 30,543, *citing*, Tenneco Gas v. FERC, 969 F.2d 1187 (D.C. Cir. 1992), with respect to the pipeline's "obvious incentive to favor its own marketing affiliate." (at 1202).

19. *Cf.* Tenneco Gas v. FERC, 969 F.2d 1187 (D.C. Cir. 1992), with respect to the pipeline's "obvious incentive to favor its own marketing affiliate." (at 1202).

pipelines the right to capacity on their own systems, whether retained as part of the restructuring process or obtained thereafter from unsubscribed or released capacity.[20]

The Commission notes, however, that a pipeline's merchant division can act as the gas purchaser's agent to make all arrangements necessary for transportation of the gas. However, the transportation would be accomplished through the use of the customer's transportation capacity in entitlement. In addition, a pipeline's marketing affiliate can obtain capacity on any pipeline and package sales and transportation but, in order to prevent circumvention of the unbundling requirement, the pipeline itself cannot do this.

IV. OPEN ACCESS TRANSPORTATION RULES

A. Application to Part 157 Shippers

In Order No. 636-A, the Commission determined that holders of individually certificated transportation under section 7(c) of the Natural Gas Act and Part 157 of the Commission's regulations (Part 157 shippers), *i.e.* not part 284 shippers, are not eligible to release capacity under section 284.243 since they are not governed by Part 284 or affected by the provisions of Order No. 636 that amended the Part 284 regulations.[21] For the same reason, the Commission found that Part 157 shippers would not have the same rights to flexible receipt and delivery points as Part 284 shippers.[22] The Commission stated that Part

20. For a discussion of transition costs, see *infra*.

21. Order No. 636-A at p. 30,569.

22. Order No. 636-A at p. 30,585.

157 shippers could convert to Part 284 if they wanted to release capacity or use flexible receipt and delivery points.

A number of petitioners seek rehearing of the Commission's restrictions on Part 157 shippers.[23] They contend the Commission did not adequately justify denying Part 157 shippers access to these essential services and treating them differently than other classes of firm transportation. They assert that Order No. 636 affected all industry segments, including Part 157 shippers. In particular, they cite to the requirement that Part 157 shippers must pay SFV rates and argue that they, like Part 284 shippers, need to release capacity to mitigate the effect of the change to SFV. They further contend that excluding Part 157 shippers from the capacity release mechanism and restricting their use of flexible receipt and delivery points eliminates available capacity from the secondary market and is incompatible with the Commission's goals of establishing a robust secondary market in released capacity and providing for maximum use of the pipeline system with little idle capacity.

The Commission denies the requests for rehearing. While the petitioners are correct that the rate design portion of Order No. 636 will apply to Part 157 shippers, the Commission's traditional policy is to apply the same rate design to all services. For example, the Commission applied the principles of its Rate Design Policy Statement to the design of Part 157 rates even though the Policy Statement was applicable only to Part 284

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23. AGA, Brooklyn Union, ConEd, JMC Power Projects, LILCO, Midland Cogeneration, National Fuel, New England Power, Northeast Energy, NYSE&G, Power Authority, PSE&G, SoCal Edison, Tenneco, TransCanada, Transco, UGI, Virginia Power (capacity release). JMC Power Projects, New England Power, Northeast Energy, Northern States, NYSE&G, PSE&G, Virginia Power (flexible receipt and delivery points).

transportation and the non-discriminatory access conditions of Part 284 did not apply to the Part 157 shippers.[24] Similarly, the competitive rationale for adopting SFV rate design as a means to promote the development of a national gas market[25] applies equally to Part 157 rates.

The rationale for applying SFV rate design to Part 157 rates does not justify extending the capacity release provisions, or other substantive aspects of Part 284, to Part 157 shippers. The regulations promulgated by Order No. 636 changed only the regulations under the Commission's open access transportation program implemented in Part 284 of the regulations.[26] The Commission's open access program always has been a special program with interrelated provisions designed to implement a comprehensive regulatory scheme. While Part 284 provisions may provide shippers with benefits not enjoyed by Part 157 shippers, it also imposes obligations not incurred by Part 157 shippers. Part 284 requires non-discriminatory access for all shippers, while Part 157 arrangements may include unique terms and conditions.[27] Important substantive provisions of Order No. 636 therefore do not apply to Part 157 shippers; for example, Part 157 shippers are not responsible for paying

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24. Interstate Natural Gas Pipeline Rate Design, 48 FERC ¶ 61,122, at p. 61,444 (1989) (order on rehearing).

25. Order No. 636 at pp. 30,431-35.

26. Order No. 636 applies only to pipelines operating under Part 284, except that it does not apply to intrastate pipelines and, as discussed later, section 284.242 applies to Part 157 capacity held by pipelines.

27. Penalties, for instance, must be imposed on all Part 284 shippers, but are not required to be imposed on all Part 157 shippers.

transition costs resulting from Order No. 636 and are not subject to pre-granted abandonment.[28]

Of particular relevance to the issue of capacity release, the Commission has a long standing policy of not permitting discounting under Part 157 in order to prevent undue discrimination. Selective discounting can take place only under the comprehensive regulatory scheme established in Part 284.[29] The capacity releasing mechanism established under Part 284 provided that the rates for released capacity could be discounted.[30] Indeed, the flexibility to discount rates for released capacity is an integral part of the capacity release mechanism because it promotes the Commission's goal of achieving efficient use of pipeline firm capacity throughout the year.[31] By discounting, firm shippers will be able to release capacity during the off peak season, when rates for capacity are most likely to be less than the maximum. Since the Part 284 capacity releasing mechanism is predicated on the ability to discount and Part 157 capacity cannot be discounted, Part 157 shippers cannot

28. *See* Order No. 636 at p. 30,459; section 284.221 (d).

29. *See* Consolidated Gas Transmission Corp., 36 FERC ¶ 61,723 (1986), *aff'd*, 39 FERC ¶ 61,112 (1987), *aff'd sub nom.*, Columbia Gas Transmission Corp. v. FERC, 848 F.2d 250 (D.C. Cir. 1988); Interpretation of, and Regulations Under, Section 5 of the Outer Continental Shelf Lands Act Governing Transportation of Natural Gas by Interstate Natural Gas Pipelines on or Across the Outer Continental Shelf, Order No. 509-A, 54 Fed. Reg. 8301, III FERC Stats. & Regs. Preambles ¶ 30,848, at p. 31,338 (1989).

30. Section 284.243 (e) provides that the pipeline must allocate released capacity to the person offering the highest rate (not over the maximum rate).

31. Order No. 636 at p. 30,418.

simply be included in the capacity releasing mechanism established under Part 284.

Some petitioners[32] argue that the Commission's determination that Part 157 shippers cannot release capacity under section 284.243 is inconsistent with the Commission's requirement that pipelines reassign their upstream Part 157 capacity under section 284.242.[33] The Commission finds no inconsistency between these determinations because the goals sought to be achieved by the two sections are unrelated. The capacity release mechanism was designed to enable firm shippers to reallocate unused capacity to replacement shippers wishing to obtain that capacity. On the other hand, the required assignment of upstream Part 157 capacity held by pipelines was necessary to implement the unbundling of sales and transportation service. After unbundling, firm shippers on the downstream pipeline would need upstream transportation to obtain access to supplies in the production area. Without upstream capacity, firm shippers on the downstream pipeline would have no means to transport gas from the production area to the downstream pipeline.[34] The reassignment of upstream pipeline Part 157 capacity, therefore, would have been necessary to implement unbundling fully, regardless of whether a capacity release mechanism was in place.[35]

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32. New England Power; SoCal Edison.

33. Order No. 636-A at p. 30,569.

34. Order No. 636 at p. 30,417.

35. Additionally, the reassignment of upstream pipeline capacity occurs only once and is permanent, while the capacity releasing mechanism is an on-going program.

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Brooklyn Union contends that since no party sought rehearing of Order No. 636, which stated that Part 157 capacity could be released, the initial decision to permit such a release became final and could not be repealed without a full notice and comment rulemaking. The Commission finds this argument unpersuasive. In Order No. 636, the regulations and preamble were inconsistent on whether Part 157 shippers could release capacity, and several parties requested clarification on this point.[36] Based on such requests, the Commission can make modifications in a major rulemaking, such as this one, without embarking on a new round of notice and comment, in particular when parties have the opportunity to comment on the proposed change.[37] Brooklyn Union was given notice and the opportunity in this round of rehearing to contest the Commission's decision regarding capacity release by Part 157 shippers.

Customers on the Great Lakes system[38] contend that denying Part 157 shippers the ability to release capacity is inconsistent with Commission Order No. 368 requiring capacity release for Part 157 capacity on the Great Lakes system in order to ration capacity effectively.[39] As the Commission found in Order No. 636-A, it will not decide case-specific issues in a generic rulemaking.[40] Case-specific concerns should be

36. *See* Order No. 636-A at p. 30,565.

37. *See* Natural Resources Defense Council, Inc. v. Thomas, 838 F.2d 1224 (D.C. Cir.), *cert. denied*, 488 U.S. 888, 901 (1988); Connecticut Light & Power Co. v. Nuclear Regulatory Comm'n., 673 F.2d 525 (D.C. Cir), *cert. denied*, 459 U.S. 835 (1982).

38. Midland Cogeneration; TransCanada.

39. 57 FERC ¶ 61,141 (1991).

40. Order No. 636-A at p. 30,561.

addressed in the particular proceeding at issue or in the pipeline's individual restructuring proceeding. Rehearing of Order No. 368 in Great Lakes still is pending before the Commission.

Although the Commission is denying the requests for rehearing, the Commission reemphasizes that it finds conversions from individually certificated transportation to open access transportation to be in the public interest. The Commission anticipates that pipelines and their customers will be able to reach agreement on proposals for implementing such conversions and encourages them to do so.[41]

Several petitioners seek clarification of the mechanism by which Part 157 shippers can convert to Part 284 transportation.[42] Some contend Part 157 shippers should be given a unilateral right to convert at any time. Others argue that the pipeline must agree. Petitioners also raise questions concerning the rate implications of conversions since some Part 157 shippers now pay rates above those charged firm customers under Part 284. They request clarification whether the rates will be converted at the higher incremental level or will be rolled-in.

As a general proposition, the details of Part 157 conversions should be worked out in the restructuring proceedings so that the conversions can be coordinated with the other aspects of compliance with Order No. 636. Part 157 shippers should notify the pipeline during the restructuring of their desire to convert. The Commission will expect pipelines to implement such

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41. *See* Transcontinental Gas Pipe Line Corp., 60 FERC ¶ 61,388 (1992).

42. PSE&G; National Fuel; Transco; LILCO; New England Power; Midland Cogeneration.

conversions to the maximum extent feasible. However, since rate and other implications of Part 157 conversions are specific to individual pipelines, the Commission cannot specify a universal mechanism for handling these concerns; these issues are more appropriately addressed in individual cases.

B. Capacity Release

In Order No. 636, the Commission added section 284.243 requiring open access pipelines to establish a mechanism that permits firm transportation customers under Part 284 to release all or part of their capacity to a replacement shipper. In Order No. 636-A, the Commission added section 284.243(h) providing an exception from the bidding requirements of section 284.243 for short-term capacity releases, modified section 284.243(d) to require pipelines to post offers to purchase capacity, and addressed numerous requests for rehearing and clarification. Except when necessary to respond to petitioners' arguments on rehearing and clarification of Order No. 636-A, the Commission will not repeat here the discussion of the capacity release mechanism in Order Nos. 636 and 636-A.

1. Maximum Rate Bids

CNG requests clarification that if a designated replacement shipper under a prearranged deal bids the maximum rate, the pipeline need not post the transaction on the EBB or, in the alternative, could post the transaction within 48 hours of the completed transaction. The Commission will clarify the appropriate handling of prearranged deals at the maximum rate (meeting all terms and conditions of the release). One of the primary goals of the capacity release provisions was to provide timely notice of all capacity reallocations and CNG has provided

no basis for concluding that such posting would be any more burdensome than posting other listings of capacity available for release. Thus, CNG's request for an exception from the posting requirements for capacity released at the maximum rate is denied; under section 284.243(d), pipelines must post immediately all capacity available for release, including those involving designated replacement shippers paying the maximum rate.[43]

However, when a prearranged deal is at the maximum rate, and meets all other terms and conditions of the release, no other shipper can make a better bid for that capacity, and, therefore, subjecting such a release to the bidding periods in the pipeline's tariff could unnecessarily delay implementation of the release. Accordingly, the Commission expects pipelines to adopt procedures to provide for prompt implementation of prearranged deals at the maximum rate.

2. Exception for Short-Term Releases

In Order No. 636-A, the Commission promulgated new section 284.243(h) providing that parties could arrange for releases of capacity of less than one calendar month without compliance with the bidding requirements of section 284.243. Notice of the release would have to made as soon as possible, but no later than 48 hours after the release transaction begins. While petitioners generally were supportive of the short-term exception, they have requested rehearing on two aspects of the provision.

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43. Releases falling under the short-term exception in section 284.243(h) must be posted as soon as possible, but not later than 48 hours after the transaction commences.

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a. Length of release

Several petitioners request that the exception be extended to one full month so that it will conform better to the industry's current practice in which contracts for spot market gas cover a full month.[44] The Commission denies the request for rehearing on this point. The short-term exception was designed to ensure that firm shippers have the ability to release capacity in unforseen situations when they cannot anticipate having capacity available. It was not designed as a substitute for the section 284.243 bidding procedures for normal industry transactions. The Commission remains convinced that pipelines can design capacity release mechanisms to accommodate the industry's standard monthly contracting process. Indeed, in most cases, the Commission expects that pipelines can implement capacity releases mechanisms under the regulations that will accommodate releases for one day or less anytime during a month and provide for consummation of such transactions within twenty-four hours of posting.[45]

b. Prohibition on roll-overs

In section 284.243(h)(2), the Commission prohibited roll-overs or extensions under the exception as well as re-releases of capacity to the same replacement shipper within 30 days of the first release. Parties wishing to extend such releases would have to comply with the posting and bidding requirements of the rule. The Commission included these prohibitions on roll-overs to protect the integrity and allocative efficiency of the capacity

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44. AGA; Natural; NYSE&G; Peoples Gas.

45. *See* Order No. 636-A at p. 30,554.

release mechanism by preventing parties from avoiding the bidding requirement by extending short-term releases.[46]

Several petitioners request the Commission to remove these prohibitions on roll-overs.[47] They contend that an exigency may reoccur within a month, requiring a re-release of capacity to the same replacement shipper. AGD gives, as an example, a power outage resulting in excess capacity to an LDC which could recur later in the month.

The Commission denies the requests for rehearing. In the Commission's judgment, the need to prevent circumvention of the bidding process should not be sacrificed to accommodate the remote possibility that an unforseen situation will reoccur more than once a month. Moreover, the Commission has provided flexibility to accommodate even such remote exigencies. The releasing shipper could release capacity to another replacement shipper under the short-term exception. As discussed previously, the releasing shipper also could enter into a pre-arranged deal with the same replacement shipper at the maximum rate. Such a deal would not be subject to any bidding periods and the Commission expects that pipelines will be able to provide for prompt implementation of such deals.

Petitioners also contend that some replacement shippers require quick access to short-term capacity on a recurring basis

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46. The Commission found that prearranged deals ordinarily must be subject to the bidding requirements of section 284.243 to preserve allocative efficiency by ensuring that capacity is allocated to the shipper placing the highest value on that capacity. Order No. 636-A at pp. 30,554-55.

47. AGA, AGD, CNG, Northern States; PSE&G; UGI; UDC; Washington Gas.

and that the prohibition on roll-overs would preclude such transactions from taking place. As noted above, the short-term exception was not intended to permit parties to structure on-going transactions involving recurring access to capacity over short periods. Such ongoing, recurring transactions must be subject to bidding (unless at the maximum rate) and the other non-discriminatory requirements of the capacity releasing mechanism to ensure that capacity is allocated to the replacement shipper placing the highest value on the capacity.

Consolidated Minerals, on the other hand, contends that the Commission's prohibition on roll-overs is not strong enough to prevent circumvention of the non-discriminatory bidding requirements of the capacity release mechanism. It requests stronger provisions, such as volumetric limitations or further limits on the frequency with which parties can use this process. The Commission will not impose volumetric limits or further restrictions to prevent roll-overs, because such restrictions would place burdens on short-term releases that do not appear necessary to prevent circumvention of the bidding process.

3. Requests for Additional Exceptions

In Order No. 636-A, the Commission rejected requests for exceptions from its rule that a replacement shipper under a prearranged deal has priority to released capacity so long as the prearranged replacement shipper meets the maximum price bid.[48] American Natural Gas and Consolidated Minerals reiterate the request for alternative priority mechanisms, arguing, in particular, that providing prearranged deals with priority to released capacity on capacity constrained pipelines will result in an unfair allocation of capacity.

48. Order No. 636-A at pp. 30,554-56.

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The Commission reaffirms its position in Order Nos. 636 and 636-A and will not provide for alternative priority provisions on capacity constrained pipelines. Such an exception could involve numerous pipelines or portions of pipelines and would defeat the efficiency goals of the capacity release mechanism. As stated in Order No. 636-A, prearranged deals promote efficiency by providing firm shippers with the incentive to market actively their unneeded firm capacity rather than simply posting it on the bulletin board. However, the Commission sought to preserve the allocative efficiency of the process by requiring that prearranged deals be subject to the bidding requirements of section 284.243 so that the available capacity is allocated to its highest valued use.[49]

Washington Gas suggests that, in Order No. 636-A, the Commission limited the use of prearranged deals to agreements between LDCs and end-users and suggests that this limitation fails to recognize that LDCs may need to enter into pooling or exchange arrangements among themselves to provide peaking service or emergency replacement of supplies in the event of a force majeure outage.[50] It further requests that the Commission permit LDCs to enter into such exchange or pooling arrangements without EBB posting.

Washington Gas is not correct that prearranged deals are limited to arrangements between LDCs and end-users; the section cited by Washington Gas merely referred to deals between LDCs

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49. In Order No. 636-A, the Commission denied a similar request for according shippers on a pipeline's firm queue with priority access to released capacity. Order No. 636-A at p. 30,555.

50. Washington Gas cites the discussion in Order No. 636-A at p. 30,555.

and end-users as an example of one type of prearranged deal. LDCs can enter into prearranged deals with other LDCs or any other potential shippers. However, Washington Gas has not demonstrated that so-called pooling and exchange arrangements, or similar arrangements, are so different from other prearranged deals that they warrant an exception from the posting requirements. All prearranged deals for release of capacity must either fall within the short-term exception in section 284.243(h) or comply with the posting and bidding requirements of section 284.243.

4. Terms and Conditions

Order No. 636 provided that releasing shippers could establish terms and conditions specific to their releases, such as the right to recall the use of capacity under certain conditions, for instance, if the temperature dropped below a specified degree.[51] In Order No. 636-A, the Commission clarified a number of issues relating to terms and conditions. The Commission stated that releasing shippers could include reasonable and non-discriminatory terms and conditions and could include provisions for determining the highest valued or best bid. The Commission required that all such terms and conditions must be posted on the pipeline's EBB, be objectively stated, be applicable to all potential bidders, and relate solely to the details of acquiring capacity on interstate pipelines.[52] With respect to the determination of best bids, the Commission also required the pipelines to include in their tariffs an objective and non-discriminatory economic standard for determining best bids. Releasing shippers could avail themselves of this standard, but were not required to do so.

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51. Order No. 636 at p. 30,418.

52. Order No. 636-A at p. 30,557.

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CIG contends the Commission erred in permitting the releasing shipper to establish terms and conditions for determining best bids and should, instead, require the pipelines and their customers to craft a generic set of evaluation criteria for determining best bids. It asserts that allowing the releasing shipper to dictate bid evaluation criteria will burden the administration of the capacity release program and could lead to discriminatory conduct, for example, if releasing shippers favor their own end-users.

The Producer Associations argue that the capacity release mechanism should protect small shippers and contend that bid evaluation should be done solely on the basis of price without consideration of the volumes bid by any shipper. Under its proposal, a shipper bidding a high price for a small volume would receive that capacity even though another shipper bid a somewhat lower price for the entire package.

The Commission denies the requests for rehearing. In Order No. 636-A, the Commission recognized that a variety of releasing conditions might exist and that one methodology for evaluating bids might not apply equally to all releases.[53] In balancing the need to permit releasing shippers to develop terms and conditions that would maximize the efficiency of their capacity releases against the need to prevent discrimination, the Commission concluded that it would not prohibit releasing shippers from developing objective, non-discriminatory terms and conditions to determine the best bid.[54] The Commission,

53. Order No. 636-A at p. 30,556. For example, the Commission recognized that in some circumstances, releasing shippers may be releasing capacity on both downstream and upstream pipelines. Order No. 636-A at p. 30,558 n.144.

54. The pipeline's tariff standard for evaluating bids would apply when the releasing shipper did not specify its own standard.

however, specifically provided that such terms and conditions could not favor one set of buyers or grant price preferences or credits to certain buyers. The Commission believes such regulations are sufficient to prevent undue discrimination. Applying objectively stated criteria also should pose little administrative difficulty. Because releasing situations are so varied, the Commission will not circumscribe the options of the parties by proscribing particular evaluation methodologies, such as those suggested by the Producer Associations.

Other petitioners raise additional issues with respect to terms and conditions. UGI and UDC reiterate the argument advanced on rehearing of Order No. 636 that releasing shippers should be allowed to establish bid evaluation criteria that reflect all factors affecting the releasing shipper; UGI contends, for example, that LDCs should be able to establish criteria to permit them to recover the cost of their own facilities that would become effectively stranded if an off-system replacement shipper acquired the LDC's pipeline capacity. PG&E contends that parties should be able to agree on prearranged deals involving terms and conditions that are not posted as conditions of the capacity release. ANR requests guidance on issues relating to recall rights, such as who will be responsible for invoking recall rights and whether the pipeline will be insulated from liability associated with proper recalls. It requests clarification that pipelines are free to devise tariff provisions to determine liability for imbalances associated with recalls.

The Commission denies these requests. The Commission continues to hold the same position it stated in Order No. 636-A. All terms and conditions for releases, including those providing for recalls, must be posted on the EBB, must be objectively stated, must apply only to release of pipeline capacity,

must not prefer any shipper, such as an end-user, over other shippers, and cannot take into account the use of an LDC's own facilities. As the Commission pointed out in Order No. 636-A, an LDC can negotiate a prearranged deal with an end-user and the end-user will receive the capacity as long as it matches the best offer.[55] Issues of defining rights and responsibilities relating to recalls should be considered in the restructuring proceedings and included in the tariff provisions in the pipelines' compliance filings.

5. Volumetric Bids

Western Resources and the Producer Associations request reconsideration of a statement in Order No. 636-A which they interpret as forbidding a releasing shipper from accepting bids for released capacity on a one-part volumetric basis. In Order No. 636-A, the Commission addressed a request to establish the maximum rate for released capacity as equal to the maximum rate for interruptible transportation. In response, the Commission stated that the maximum rate for released capacity normally would be the maximum firm rate since the releasing shipper is releasing firm capacity and the replacement shipper is paying a monthly reservation charge.[56] The Commission, however, was addressing the maximum rate issue only with respect to this common releasing scenario. As a general policy, the Commission seeks to promote competition between pipeline capacity and released capacity. To facilitate such competition, the Commission will not foreclose released capacity from being bid on a volumetric basis. The Commission will clarify that parties to the restructuring proceedings can propose mechanisms that

55. Order No. 636-A at p. 30,555.

56. Order No. 636-A at p. 30,560.

would permit shippers to release capacity on a volumetric basis if they choose to do so.

6. Use of Released Capacity for Backhauls

WGM requests clarification that a releasing shipper can release capacity it currently uses as a forward haul for use as a backhaul, if such use is operationally feasible. WGM contends that a backhaul resulting in a change in the flow direction should be permitted if such a change is operationally feasible or if the shipper is willing to pay the cost of making it feasible.

In Order Nos. 636 and 636-A, the Commission established the general principle that firm shippers should be able to make full use of their pipeline capacity through release transactions. The Commission used as an example a releasing shipper with capacity between the Gulf of Mexico and New York releasing capacity from the Gulf to Atlanta; this transaction would then free up an equal amount of capacity from Atlanta to New York which the shipper could release or use itself.[57] The releasing shipper could release its capacity in this manner even though the total amount of gas delivered from the two transactions could exceed its total reservation quantity from the Gulf to New York. This principle should be applied to capacity release arrangements between releasing and replacement shippers that involve backhauls or exchanges. The Commission, however, cannot make a generic determination on WGM's questions with respect to physical changes in flow direction, since operational questions must be determined on the basis of the characteristics of each pipeline.

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57. Order No. 636-A at p. 30,559 n.151.

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7. Credits Exceeding Reservation Fee

Section 284.243(f) provides that releasing shippers receive the full proceeds from any release. In Order No. 636-A, the Commission denied requests for modifying this principle as applied to shippers paying discounted rates.[58] Three petitioners seek rehearing of the Commission's determination that shippers holding discounted contracts should receive the full proceeds from a release, making essentially the same arguments addressed in Order No. 636-A.[59] They contend that the pipeline entered into discounted contracts based on specific circumstances in order to retain firm transportation that was in danger of being lost, the pipeline will be harmed if these customers could release their capacity to other shippers, and the holders of discounted contracts would enjoy an advantage over shippers paying maximum rates.

For the reasons stated in Order No. 636-A, the Commission again denies the requests for rehearing. Holders of discounted capacity have no competitive advantage in the release market over shippers paying maximum rates, since all firm shippers will be releasing capacity under the same conditions.[60] Further, as the Commission pointed out, pipelines are no worse off if holders of discounted contracts can release capacity; the pipeline still receives the same total reservation charges and revenue as it did prior to the release.

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58. Order No. 636-A at pp. 30,561-62.

59. Arkla; CIG; Enron.

60. Replacement shippers will be able to bid for all available capacity up to the same maximum rate and therefore will have no incentive to favor a release from a shipper holding discounted capacity over a release from a customer paying the maximum rate.

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8. Capacity Releasing by Small Customers Paying a One-Part Rate

In Order No. 636-A, the Commission clarified that pipelines offering a small customer sales or firm transportation service at an imputed load factor rate must continue to offer firm and no-notice transportation on the same basis.[61] Several petitioners request rehearing or clarification, contending that the small customers electing service under a one-part volumetric rate should be prohibited from releasing capacity under the capacity release mechanism of section 284.243.[62] They contend that permitting such releases would provide these customers with a double benefit or would provide them with competitive advantages in the releasing market. If the Commission permits small customers to release capacity, the Northern Distributor Group contends that the release should be at a rate equal to the pipeline's two-part rate, while Southern argues that the small customers should be required to pre-pay their one-part rate prior to releasing. Prior Energy, on the other hand, argues that small customers should be able to release capacity and requests clarification of the maximum rate for such releases.

Because small customers paying a one-part volumetric rate are not paying a reservation charge to reserve the capacity, the Commission clarifies that they cannot release that capacity under the capacity release mechanism.[63] However, small customers

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61. Order No. 636-A at p. 30,600.

62. Atlanta Gas; Northern Distributor Group; Southern.

63. The capacity release mechanism was designed so that payments from a replacement shipper will be credited to a releasing shipper's reservation charge. *See* section 284.243(f).

paying a two-part rate including a reservation fee will be permitted to release that capacity. The parties in the restructuring proceedings should work out details relating to releases of capacity under small customer two-part rate schedules, including the development of procedures to enable customers served under a one-part rate schedule to convert to a two-part rate schedule if they choose to convert in order to release capacity.

9. Responsibility for Penalties

Section 284.243(f) provides that, unless the pipeline agrees otherwise, a releasing shipper remains liable under its contract with the pipeline. In Order No. 636-A, the Commission clarified that if a replacement shipper defaults, the releasing shipper is responsible to the pipeline for the continued payment of reservation charges, but not for penalties or other charges incurred by the replacement shipper as a result of its own conduct.[64] Arkla requests clarification that releasing shippers still will be ultimately liable for monthly surcharges, such as GSR charges, and other charges not the result of the replacement shipper's conduct. CNG requests clarification that the Commission was not predetermining the issue of a releasing shipper's liability and that a releasing shipper can be held liable for penalties if it is partly responsible for the conduct.

In Order No. 636-A, the Commission set out the general parameters for determining whether releasing shippers should be liable for penalties and other charges in the event of defaults by the replacement shippers. As a general matter, releasing shippers are ultimately responsible for items included in reservation charges (amounts for which they would be responsible if no release took place), but are not responsible for

64. Order No. 636-A at p. 30,565.

assessments included in the usage charge or penalties caused by the conduct of replacement shippers. For example, releasing shippers ultimately would be responsible for payment of a full reservation fee and any GSR demand surcharge applicable to that fee. The parties in the restructuring proceedings should craft appropriate tariff language along those lines.

10. Contractual Privity

UGI and UDC repeat the request, denied in Order No. 636-A, that the Commission establish contractual privity between releasing and replacement shippers. UDC suggests that releasing shippers be able to include, as a term and condition of release, an indemnification agreement between the releasing and replacement shipper. As determined in Order No. 636-A, the Commission will not compel pipelines to require contractual privity between releasing and replacement shippers, since privity and subrogation are matters of state law and should be governed by that law and the contracts of the releasing shipper and the pipeline.[65] Releasing shippers can include any non-discriminatory term and condition in their offers to release and therefore could include the requirement for replacement shippers to enter into an indemnification agreement, but the interpretation of any such agreement would be a matter for state law.

11. Releasing Shipper's Liability

Barclays and Mojave request clarification that the capacity releasing mechanism will not impair the ability of pipelines to

65. "[P]robably there are few doctrines better established than that a surety who pays the debt of another is entitled to all the rights of the person he paid to enforce his right to be reimbursed." Pearlman v. Reliance Insurance Co., 371 U.S. 132, 136-37 (1962).

recover their full cost-of-service. Barclays seeks assurance that a project financed pipeline will be protected from a shortfall in price and in contract duration when capacity is reassigned. Mojave seeks clarification that it will be able to tailor its capacity release program to deal with case specific issues stemming from the rate design and contracts on its system so as to ensure its ability to recover its cost-of-service.

As discussed in Order No. 636-A, the capacity release mechanism promulgated in section 284.243 does not change the relationship between the firm capacity holder (releasing shipper) and the pipeline and therefore will not result in any diminution of revenue received by the pipeline. Section 284.243(f) provides that the contract of the releasing shipper and the pipeline still remains in full force and effect.[66] As the Commission explained in Order No. 636-A, the releasing shipper is therefore ultimately responsible for paying the pipeline the full amount of its reservation fee.[67] The Commission will consider Mojave's or any other case specific concerns in the restructuring proceedings for each pipeline.

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66. Similarly, the Commission clarified in Order No. 636-A that for capacity reallocations on project financed pipelines under sections 284.14(e) and 284.242, an assignor of capacity must serve as a guarantor of payments under the existing contract unless creditor approval of the assignment is obtained, where necessary, and the project financed pipeline agrees to release the assignor from liability. Order No. 636-A at p. 30,674.

67. Order No. 636-A at p. 30,560. The pipeline will bill the replacement shipper for the amount it bid for the reservation fee (to be credited to the releasing shipper) and for the applicable usage fee. For accounting purposes, the pipeline bill to the releasing shipper should reflect a simultaneous credit to the releasing shipper for the reservation fee billed the replacement shipper. If the replacement shipper defaults, the pipeline will bill the releasing shipper for the unpaid amount on the next bill.

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12. Interruptible Rate Design

In Order No. 636-A, the Commission addressed issues regarding the development of a rate design for interruptible transportation after the implementation of a capacity release mechanism.[68] The Commission traditionally has required that a pipeline recover a certain amount of fixed costs (its revenue responsibility) from interruptible transportation based on a projected level of interruptible throughput. On rehearing of Order No. 636, several parties were concerned about the difficulty in accurately projecting interruptible throughput and revenue responsibility when the pipelines and their customers have had no experience with the effect of capacity releasing on the throughput levels for interruptible transportation. The release of firm capacity also may affect the rates charged for interruptible transportation since the competition from released capacity might require the pipelines to offer greater discounts for interruptible transportation than they had in the past.[69]

In Order No. 636-A, the Commission found that promoting competition between released and interruptible transportation was an important policy objective. The Commission recognized that competition between released firm and interruptible transportation, together with the potential use of seasonal contract demands, could affect the level of interruptible transportation and provided that the throughput mix between

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68. Order No. 636-A at pp. 30,562-63.

69. For example, if the projected revenue responsibility for interruptible transportation were higher than actual experience, the pipeline might not recover the fixed costs assigned to interruptible transportation. On the other hand, if the projection were too low, the pipeline could recover much more than the costs allocated to the interruptible service.

interruptible and firm transportation should be considered in the restructuring proceedings.[70] In handling this issue, the Commission stated that the parties to the restructuring proceedings could consider a variety of approaches, such as agreeing on an appropriate level of throughput for interruptible transportation or some type of revenue crediting mechanism. Although not mandating the adoption of any technique, the Commission provided an outline of a potential revenue crediting approach under which the pipeline would allocate no costs or revenue responsibility to interruptible service, but would credit firm shippers with interruptible revenue generated. The firm shippers would receive the credit because under this allocation of costs, the firm rate would recover all the fixed costs of the pipeline.

Several petitioners contend that the Commission erred in even suggesting that a revenue crediting mechanism might be appropriate for dealing with the difficulty of projecting interruptible revenues.[71] They contend that revenue crediting is inconsistent with section 284.7(d)(2) of the Commission's regulations, which provides that rates must be designed to recover costs on the basis of projected units of service. They assert that revenue crediting conflicts with the purpose of this section, because it provides the pipeline with no incentive to provide the service. LILCO argues that interruptible transportation should be subject to the same posting and bidding requirements as released capacity to ensure that neither interruptible nor released capacity will have an inherent advantage over the other service. Although not entirely clear from its comments, LILCO appears to propose that pipelines be obligated to sell interruptible

70. Order No. 636-A at p. 30,563.

71. Arcadian; ConEd; Industrial Groups.

service to the highest bidder, rather than being able to selectively discount.

The petitioners requesting rehearing have not been aggrieved by the suggestion that the Commission would consider a revenue crediting approach proposed in a specific restructuring proceeding. In implementing its regulations, the Commission will not adopt rigid rate-making methodologies that fail to reflect the reality of the market or the intent of its regulations. When the Commission permitted discounting of interruptible transportation, it had to adopt rate-making methodologies for projecting revenue responsibility that would not penalize the pipeline for discounting interruptible service.[72] The Commission suggested a similar revenue crediting mechanism as a means of dealing with the difficulty of estimating discounting.[73] The Commission will not foreclose the parties in the restructuring proceedings from considering revenue crediting or other approaches, such as LILCO's proposal for bidding on interruptible transportation, as methods for dealing with the uncertainties resulting from the implementation of a capacity releasing mechanism.[74] If the Commission adopts a revenue crediting or other approach in a pipeline's compliance filing, it will reevaluate any such mechanism in the pipeline's next rate case after the parties have experience with capacity releasing.

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72. *See* Associated Gas Distributors v. FERC, 824 F.2d 981, 1012 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

73. Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295, at pp. 62,056-57 & n. 49 (1989).

74. In response to LILCO's request that interruptible capacity be subject to the same posting requirements as released capacity, the Commission notes that section 284.9(b)(3)&(4) already requires pipelines to post information about interruptible service on an EBB.

Questar requests clarification that under a potential revenue crediting approach the pipeline would not have to credit firm shippers for the portion of interruptible revenue reflecting its variable costs (usage charge). The Commission will clarify that the revenue credit should apply only to the extent that revenues from interruptible transportation recover costs allocated to firm transportation. Pipelines would be able to retain the usage component of the interruptible rate so long as the usage charge is calculated on the basis of total throughput.

13. Administrative Issues Involving Capacity Release

a. Electronic bulletin board

In Order No. 636, the Commission required that pipelines conduct their capacity release programs through electronic bulletin boards (EBBs). In Order No. 636-A, the Commission directed the pipelines to provide for interactive EBBs in their compliance filings or to provide a reasonable explanation of their inability to do so.[75] The Commission further encouraged the industry to develop uniform standards and conventions for EBBs and committed to establish a technical conference to determine the industry's progress in developing interactive, user-friendly EBBs and uniform EBB standards.

Williston and ANR request clarification of the requirements needed to make EBBs interactive, since they claim capacity release is not simply a transaction between the releasing and replacement shipper, but requires some pipeline involvement. ANR suggests that, in certain situations, transactions could be consummated on the EBB without any, or with limited, pipeline intervention.

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75. Order No. 636-A at p. 30,549-50.

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The Commission did not seek to define the precise parameters of an interactive EBB, believing that the industry, through the restructuring proceedings, is in the best position to reach such determinations. As a general matter, the Commission expects pipelines to provide EBBs that will permit posting of capacity available for release and bids for that capacity directly on the EBB, and electronic confirmation of the completed transaction on the EBB. The Commission envisions that, in the near future, all pipelines should be able to provide for entire transactions to take place using EBBs, including, for example, electronic contractual consummation of completed transactions.

UGI and the Industrial Groups argue that EBBs are the key to capacity reassignment and that the Commission must take action to ensure that EBBs on different pipelines are coordinated. They urge the Commission to defer mandatory bidding through EBBs until a coherent national or regional EBB policy is established. UGI reasserts its position that facilities and personnel running the EBB should be separate from those used for managing interruptible transportation to ensure that the pipelines do not abuse the EBB process for competitive purposes.

The Commission will not defer the requirement for conducting capacity release transactions through an EBB. The capacity release mechanism is an integral part of the restructuring required by Order No. 636 and therefore must be implemented at the same time as the other requirements of Order No. 636 to ensure that the parties have a mechanism for reallocating capacity.[76] While the Commission believes that EBB technology

76. As discussed in Order No. 636-A, the Commission will not permit reallocations of capacity to take place without compliance with the posting

(Cont'd)

and coordination may improve over time, it is convinced that the pipelines currently have the ability to develop effective EBBs and capacity release mechanisms. The Commission also believes that the industry, not the Commission, is in the best position to develop the specific technical standards for EBBs and for coordination among EBBs. The Commission considers its most effective role as facilitating the process of improving EBBs by bringing those with the technical expertise together in a technical conference.

The Commission adheres to its determination in Order No. 636-A that separation of EBB personnel is not necessary to prevent the pipelines from giving undue preference to their own interruptible transportation. As discussed in Order No. 636-A, the Commission has taken a number of steps which it believes are all that is currently needed to address this issue.[77]

b. Implementation of releases

ANR and CIG request clarification that pipelines can adopt procedures for capacity release that provide sufficient advance notice to accommodate the pipelines' contract administration process. The Commission is not sure whether these requests apply to releases under the short-term exception or under the general bidding requirements of the capacity release mechanism.

With respect to the short-term exception under section

(Cont'd)
and bidding requirements of section 284.243 to ensure that capacity reallocations can be effectively monitored for possible undue discrimination. Order No. 636-A at pp. 30,552-53.

77. Order No. 636-A at pp. 30,563-64.

284.243(h), the Commission adopted this exception specifically to avoid any impediments to short-term releases of capacity and therefore the pipelines should not adopt any procedures that would interfere with the execution of releases under the short-term exception. With respect to releases under the general provisions of section 284.243, the Commission reiterates its position in Order No. 636-A that, in most instances, pipelines should be able to provide procedures to accommodate short-term releases on the EBB so that release transactions can take place for one day or less any time during the month and that such transactions can be finalized within 24 hours.[78] Pipelines must justify any provisions that do not meet this standard. In Order No. 636-A, the Commission suggested that the parties to the restructuring proceedings consider pre-qualification for creditworthiness as a means to expedite releases,[79] and they similarly should consider appropriate mechanisms for dealing with contract execution and other issues so as to ensure a viable capacity release mechanism.

c. Administrative fee

In Order No. 636-A, the Commission provided that pipelines could not recover the costs of operating their capacity release programs through a separately stated administrative fee, but instead should include the fixed costs of their programs in their rates. The pipelines, however, could charge a fee for using the EBB that reflected the variable costs of such use.[80] In addition, the Commission required that pipelines must permit

78. Order No. 636-A at p. 30,554.

79. Order No. 636-A at p. 30,558.

80. Order No. 636-A at p. 30,564.

posting on the EBB of offers to purchase capacity and stated that the shipper posting such offer would have to pay any posting fee required.[81]

CIG and Tenneco request rehearing, contending that the Commission should permit a separately stated administrative fee for using the EBB that covers fixed and variable costs so that only shippers making use of the EBB would pay the costs of providing the service. ANR and CNG request clarification that the separately stated usage fee reflecting variable costs would be charged to the users of the EBB, not through commodity rates. CNG also requests clarification that the Commission's reference to a posting fee for offers to purchase capacity refers to the separately-stated usage fee for use of the EBB.

The Commission required the pipelines to recover the fixed costs for operating the capacity release program through their rates to ensure that the market for released firm capacity was not unduly burdened by high rates for using the EBB and thereby placed at a disadvantage to interruptible capacity. The Commission continues to find this rationale persuasive and therefore denies CIG's and Tenneco's requests for rehearing. The Commission reiterates that the pipelines may charge a separately stated usage fee, reflecting only the variable costs of usage, charged to those using the EBB.[82] The Commission clarifies that shippers posting offers to purchase capacity can be charged only the same usage fee assessed other users of the EBB.

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81. Order No. 636-A at p. 30,565.

82. Pipelines need to demonstrate that the costs included in the EBB usage charge reflect only the variable costs of customers' use of the EBB.

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14. Retention of Capacity Brokering

In Order Nos. 636 and 636-A, the Commission concluded that, with the adoption of a capacity release mechanism, it should not approve new individually authorized capacity brokering and other capacity assignment certificates. In addition, in a separate order issued April 8, 1992, the Commission amended the terms and conditions of existing capacity brokering and other assignment programs to conform to the capacity reallocation mechanisms adopted in Order No. 636.[83]

The AGA argues that the Commission should allow the parties to the restructuring proceedings to develop workable alternatives to capacity releasing under the rule and not ban programs similar to capacity brokering. The AGA concludes that "where state commissions are actually regulating, or seek to regulate, capacity brokering, it would be beneficial to allow capacity brokering programs to develop under state purview."[84]

For the reasons given in Order Nos. 636 and 636-A and in the *Algonquin Gas Transmission Co.* orders of May 8 and August 3, 1992,[85] the Commission denies AGA's request for rehearing. In brief, the Commission believes that exclusive federal regulation of interstate capacity assignment programs is necessary to establish a uniform capacity reallocation program, which the Commission can monitor to ensure that the secondary transportation capacity market operates without discrimination.

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83. Algonquin Gas Transmission Co., 59 FERC ¶ 61,032 (1992), *reh'g denied*, 60 FERC ¶ 61,113 (1992).

84. Petition at 4.

85. 59 FERC ¶ 61,032 and 60 FERC ¶ 61,113 (1992).

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15. Buy/Sell Arrangements

The Commission concluded in *El Paso Natural Gas Co.* that it has jurisdiction over buy/sell arrangements where, for example, an LDC purchases gas in the production area from an end user or merchant designated by an end user, ships the gas on its (the LDC's) own capacity, and sells the gas to the end user at the retail delivery point.[86] In Order Nos. 636 and 636-A, the Commission concluded that as of the effective date of a pipeline's compliance with Order No. 636, no new buy/sell arrangement can be consummated and all allocations of capacity must be done under the capacity releasing mechanism.

PSE&G asks the Commission whether the Commission's ban applies only to LDCs or also applies to marketers and producers. The Commission concludes that the prospective ban on buy/sell arrangements applies to all holders of capacity on an interstate pipeline for the reasons set forth in *El Paso*, *supra*. The Commission sees no difference between LDCs and other capacity holders with respect to the Commission's determination "that to permit the coincidence of buy/sell transactions with capacity reallocation under the mechanism established in Order No. 636 would interfere with our objectives in creating a nationally uniform [capacity release] program."[87]

16. Jurisdiction Over Municipalities

In Order No. 636-A, the Commission concluded that while

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86. 59 FERC ¶ 61,031 (1992), *order denying reh'g and clarifying prior order*, 60 FERC ¶ 61,117 (1992), *appeal docketed*, Windward Energy & Marketing Co. v. FERC, No. 92-1361 (D.C. Cir. Aug. 13, 1992).

87. 60 FERC ¶ 61,117 at p. 61,384.

municipalities are beyond the jurisdiction of the Commission, they may release capacity on a pipeline only by complying with the procedures pertinent to the pipeline's releasing mechanism because the conditions of the program pertain to the mechanics of the release by and through the pipeline.

The APGA and Citizens Gas seek rehearing of the Commission's conclusion that municipalities must comply with the requirements of a pipeline's capacity release program. They argue that the Commission has exceeded its authority under the NGA because a municipality is not a natural gas company as defined in NGA section 2. They add that the Commission has expressly held in two orders with respect to capacity brokering that municipalities are not subject to the Commission's NGA jurisdiction.[88] They maintain that the difference between capacity brokering and releasing — that is, that under the former assignments may be effected directly while under the latter may only be effected through the pipeline — does not modify the NGA's exemption for municipalities. The APGA maintains that municipalities may release capacity without restriction on the contractual price negotiated or the choice of buyer. Citizens Gas contends that municipalities may not be subjected to Commission action that would restrict substantially their ability to release, including by implication buy-sell agreements.

The Commission denies rehearing. While the Commission has no NGA jurisdiction over municipalities as gas sellers or transporters, the Commission has exclusive preemptive jurisdiction over access to interstate pipeline capacity.[89] The

88. Texas Eastern Transmission Corp., 51 FERC ¶ 61,170 (1990), Texas Gas Transmission Corp., 55 FERC ¶ 61,208 (1991).

89. See the discussion in El Paso Natural Gas Co., 60 FERC ¶ 61,117 at p. 61,384 (1992).

Commission's authority over transportation by a pipeline under the NGA includes the eligibility criteria for becoming a shipper.[90] The Commission sees this as no different from its authority to determine terms and conditions of service, which the APGA concedes municipalities should abide by.[91] Whether the shipper is a natural gas company is irrelevant to the Commission's plenary authority over access to interstate pipeline capacity under the NGA.

The cases cited by petitioners are not on point. It is true that they hold that municipalities need not be certificated in a capacity assignment program and that they need not comply with conditions imposed upon program participants as transporters. However, as the Commission concluded in Order No. 636-A, those cases are not controlling when the Commission has exercised its authority to require that releases be effected by and through the pipeline. In that event, the capacity releasing mechanism in its entirety must be complied with just as a municipality must comply with any other pipeline term or condition of service. To allow municipalities to freelance their releasing would not be in harmony with the Commission's goals of a uniform capacity reallocation program to eliminate discrimination in the assignment of pipeline capacity. Of course, the municipalities are not covered by the Commission's grant of a limited jurisdiction certificate in section 284.243(g) of the Commission's regulations.

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90. *Cf.* Mississippi River Transmission Corp. v. FERC, 969 F.2d 1215, 1217 (D.C. Cir. 1992) (The Commission's authority over the transportation of gas in connection with an unregulated direct sale "is beyond dispute.")

91. *Cf.* FPC v. Louisiana Power & Light Co., 406 U.S. 621 (1972) (The Commission has authority over curtailment programs under its jurisdiction over transportation).

Finally, to grant APGA's request would create a regulatory gap that would frustrate the non-discrimination feature of Order No. 636. Most municipalties are self-regulated (*i.e.*, not subject to state commission authority). To grant APGA's request would, therefore, create a class of shipper controlling access to interstate capacity without either federal or state commission review. This regulatory gap would give municipalities a competitive and otherwise non-market advantage over all other shippers. Simply put the fundamental premise of capacity releasing — to ensure non-discriminatory access to the secondary transportation market — would be undermined. Allowing such a regulatory gap to exist in regulatory access to the interstate market is not in the public interest.

C. Upstream Capacity Assignment

In Order No. 636, the Commission adopted new section 284.242 of its regulations, which provides that open-access pipelines must allow firm transportation customers of downstream pipelines to acquire capacity on upstream pipelines held by downstream pipelines. The main issues raised are whether bundled sales customers should have a priority in acquiring upstream capacity and whether downstream pipelines can retain upstream capacity.

1. Priority for Bundled Sales Customers

UDC argues that the Commission must amend section 284.242 of the regulations to state affirmatively that firm sales customers of a pipeline have first priority to allocation of upstream transportation capacity formerly used to provide the pipeline's bundled sales service. It states this will reflect Order No. 636-A's statement that "customers of downstream pipelines

have priority access to upstream transportation and storage capacity."[92] UGI also argues that section 284.242 should be amended so that the phrase "without undue discrimination" does not compromise converting customers' priority rights in the allocation of all upstream capacity and storage.[93] UGI maintains that this right is necessary to continue the level of firm deliverability embedded in converting sales customers' prior sales contracts.

The Commission clarifies that current bundled firm sales customers of downstream pipelines have a priority right during the restructuring proceeding over other pipeline customers to upstream transportation and storage capacity to the extent that capacity is needed to maintain their pre-restructuring level of maximum daily entitlement to service. This is not an absolute right because there may be circumstances where upstream transportation or upstream storage or both are not necessary to maintain the downstream pipeline customer's level of maximum

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92. Order No. 636-A, at p. 30,568. UDC also states that "Order No. 636-A clarified that current bundled firm sales customers of pipelines have a priority right to upstream and storage necessary to maintain their level of maximum daily entitlement to service, whether or not they elect no-notice transportation service." Petition at 15. However, Order No. 636-A at the cited text referred only to downstream storage. Order No. 636-A at p. 30,578.

93. Section 284.242 provides as follows:

> An interstate pipeline that offers transportation service on a firm basis under Subpart B or G of this part must offer without undue discrimination to assign to its firm shippers its firm transportation capacity, including contract storage, on all upstream pipelines, whether the firm capacity is authorized under Part 284 or Part 157.

daily entitlement. This parallels the Commission's conclusions in Order No. 636-A that current bundled firm sales customers have a priority right to the storage necessary to maintain their level of maximum daily entitlement to service and that customers that converted earlier were able to do so without access to storage. If upstream capacity or storage is available after bundled firm sales customers elect their levels of capacity, the pipeline must offer and allocate the remaining capacity among all its shippers on a nondiscriminatory basis. That is, current system users other than bundled firm sales customers have no priority over new transportation customers for upstream transportation and storage capacity that is not selected by current bundled firm sales customers.

The Commission will not amend section 284.242 because this is a capacity allocation matter. The priority for bundled firm sales customers does not contravene the requirement that the downstream pipeline offer its upstream capacity without undue discrimination because the allocation priority is reasonable when necessary to preserve the bundled firm sales customer's level of pre-restructuring maximum daily entitlement upon conversion to unbundled service.

2. Retention of Upstream Capacity By Pipelines

The Commission previously denied requests that pipelines be permitted to retain capacity on their own systems downstream of the point of unbundling on their systems. ANR seeks rehearing of the Commission's statement that a downstream pipeline holding capacity on upstream pipelines may not perform a sales service at the interconnection with an upstream pipeline. It argues that a pipeline will be unable to compete with other merchants, that it will be precluded from selling gas

supply under contract, and will be forced to buy out marketable gas supplies with little or no leverage. It adds that its suppliers will demand the higher market price from ANR's former customers.

Natural refers to Order No. 636-A's prohibition on downstream pipelines holding capacity on upstream pipelines as properly interpreted to mean that a pipeline sales division cannot retain upstream capacity on a preferential basis. It is concerned that Order No. 636-A could be interpreted to preclude the pipeline sales division from holding any capacity on other pipelines upstream of the point of unbundling, which would freeze it out of access to significant supply areas during the restructuring proceedings.

UGI argues that the Commission should allow downstream pipelines to show that it is necessary for them to retain title to upstream capacity to meet their existing firm transportation obligations to their customers for both peak-day entitlements and quality of service. UGI maintains that the quality of service provided by Columbia Gas Transmission Company will likely be lower than it is now if Columbia must assign its over 80 interconnections with upstream pipelines on a piecemeal basis. Arkla contends that downstream pipelines should be able to retain title to, but not the use of, upstream capacity to provide greater flexibility to the pipeline.

The Commission adheres to its conclusion that downstream pipelines may not hold capacity on upstream pipelines to perform a sales service at the interconnection with an upstream pipe-line.[94] Pipelines, such as ANR and Natural, can still compete

94. As stated in Order No. 636-A, downstream pipelines can hold capacity on upstream pipelines in the production area. Order No. 636-A at p. 30,566.

with other merchants by selling, in the production area, gas supplies under contract or obtained in the future. Pipelines, as merchants, are not forced to buy out marketable gas supplies nor are they frozen out of significant supply areas. Natural's interpretation, that the Commission has prohibited only retention of upstream capacity on a preferential basis, is incorrect because that would permit a pipeline to sell gas at downstream interconnections with upstream pipelines. As noted earlier, a pipeline's marketing affiliate can obtain capacity on any pipeline.

As stated in Order No. 636-A, downstream pipelines can retain some capacity on upstream pipelines to the extent they demonstrate it to be necessary for operational management and balancing purposes and the performance of the no-notice transportation service.[95]

To the extent UGI's and Arkla's arguments involve operational concerns, they are case-specific. Hence, UGI and Arkla should raise their concerns in the relevant restructuring proceedings.

Of course, the Commission recognizes that, on some pipelines, operational problems could arise owing to the assignment of upstream capacity involving many interconnections and downstream customers. Hence, the parties to the restructuring proceeding are encouraged to develop innovative proposals to deal with this problem. For example, it may be adequate for the downstream customers to appoint an agent to arrange transportation for them as a group or they could take some form of joint title to the upstream capacity (*e.g.*, an undivided interest).

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95. Order No. 636-A at pp. 30,566-67.

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3. Relationship of Section 284.242 to Restructuring

Order No. 636-A stated that a downstream pipeline may reduce its upstream capacity "with the consent of the potentially affected customers of the downstream pipeline."[96] ANR maintains that one or two customers should not be able to refuse to consent and cause all customers to incur the cost of unneeded capacity so that the two can reserve capacity for possible future use. ANR suggests the Commission "impose a presumption that a customer's election not to receive a permanent assignment of capacity is deemed an assent by that customer to a capacity reduction or termination under section 284.14(c)(4)."[97]

The Commission denies ANR's request. The requirement of unanimity only pertains to consent to assignment or relinquishment of upstream capacity in the restructuring proceeding. It is necessary to ensure that customers of downstream pipelines have adequate opportunity to make their decisions about upstream capacity during the restructuring proceeding. Once the upstream pipeline completes its restructuring process, the downstream pipeline may release its Part 284 capacity under section 284.243 of the Commission's regulations without the consent of downstream customers. If that release is permanent, then it will not be available for the downstream customers to take assignment under section 284.242. If the release is not permanent, the downstream customer may exercise its section 284.242 rights, subject to the release.

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96. Order No. 636-A at p. 30,641. *See also id.* at p. 30,568.

97. Petition at 8.

4. Timing Of Implementation

Transco asks the Commission to clarify how and when the assignments under section 284.242 are to be accomplished. Transco maintains that it should be able to make those assignments to its shippers on a self-implementing basis prior to the effective date of its Order No. 636 compliance filing because section 284.242 became effective on May 18, 1992, and because Order No. 636 stated that "section 284.242 capacity reassignments '*must* be effectuated in the restructuring proceedings' prior to release of capacity under new section 284.243."[98] Transco further asserts that one upstream pipeline has notified Transco that the upstream pipeline interprets Order No. 636 to preclude the effectiveness of upstream capacity assignments until the restructuring proceedings are completed and that it would not consent to Transco's assignments until it received assurance that its service obligation to Transco was superseded by its service obligation to the shippers obtaining assigned upstream capacity. Last, Transco points out that the Commission has stated it will allow early implementation of certain aspects of Order No. 636, such as open access storage and capacity releasing.[99]

Brooklyn Union supports Transco's motion and argues that consent by upstream pipeline suppliers is not required to effectuate permanent assignments of upstream capacity and that, upon such assignment, the upstream pipeline's service

98. Motion for Clarification at 2, *citing* Order No. 636 at p. 30,417 n. 120.

99. *Citing* Northern Natural Gas Co., *et al.*, 59 FERC ¶ 61,362 at p. 62,363 (1992). *See also* ANR Pipeline Co., 59 FERC ¶ 61,205 at p. 61,724 (1992).

obligation to the downstream pipeline is replaced and superseded by its obligation to the new firm shipper.[100] Brooklyn Union maintains that, to effectively evaluate the available range of services, shippers need to know the full amount of upstream and on-system capacity available to them.

Natural responds that it supports upstream capacity assignments prior to full implementation of Order No. 636 by the downstream pipeline only if the upstream pipeline consents. It maintains this is necessary so that a downstream pipeline that has not complied with Order No. 636 cannot gain a temporary competitive advantage. Natural adds that an assignee of upstream capacity must meet the upstream pipeline's creditworthiness provisions as is the case for replacement shippers under section 284.243.[101]

Section 284.14(b)(i) of the Commission's regulations requires pipelines to make a compliance filing that, among other things, implements Subpart H of Part 284, including provisions to implement "assignment of capacity rights on upstream pipelines to firm customers."[102] Hence, assignments under section 284.242 are not self-implementing for the downstream pipeline; it must implement such assignments through its compliance filing with the Commission. This is necessary so the Commission can resolve any issues involving the appropriate allocation of capacity by downstream pipelines on upstream pipelines.

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100. Brooklyn Union's motion for leave to answer Transco's motion is granted.

101. Order No. 636-A at p. 30,558.

102. 18 CFR 284.14(b)(l)(xiv).

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The Commission will permit a downstream pipeline to make a compliance filing in its RS docket to implement its upstream pipeline capacity assignment prior to the effective date of other aspects of its compliance filing under Order No. 636. The downstream pipeline must include in its compliance filing its allocation methodology, including how it will take into account the rights of current bundled sales customers to upstream capacity.[103] Natural should raise its objections to early approval in response to the downstream pipeline's compliance filing.

Upstream pipelines do not have to file tariff provisions to implement section 284.242. However, they must permit the assignment, even if it is prior to the effective date of the upstream or downstream pipeline's compliance filing under Order No. 636. Because the assignee has met the downstream pipeline's creditworthiness requirements, the Commission sees no reason for it to requalify under the upstream pipeline's standards. In any event, the Commission has not been made aware of situations where upstream and downstream pipelines have significantly different creditworthiness requirements. The assignment of upstream capacity will result in a new transportation agreement under Part 284 between the upstream pipeline and the assignee.[104] Upon the effective date of that agreement, the contractual arrangement between the upstream pipeline and downstream pipeline is terminated and abandonment is authorized as stated in Order No. 636-A.[105]

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103. See Part C.1., *supra* with respect to the priority of current bundled sales customers to upstream capacity.

104. Even if the downstream pipeline held capacity on the upstream pipeline under Part 157, the transportation agreement between the assignee and the upstream pipeline will fall under Part 284. This will provide the assignees with the flexibility to fully utilize available sources of supply.

105. Order No. 636-A at p. 30,567.

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D. No-Notice Transportation Service

In Order No. 636, the Commission required pipelines to provide a no-notice transportation service under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty. Petitioners raise a variety of issues dealing with the availability of and eligibility to receive no-notice service.

1. Availability of No-Notice Service

In Order Nos. 636 and 636-A, the Commission concluded that a pipeline was required to offer a no-notice transportation service only to customers that were entitled to receive a no-notice, city-gate, firm sales service on May 18, 1992, and that pipelines are not required to offer a no-notice service to other customers because they have not been receiving such a service. The Commission encouraged the pipelines to offer a no-notice transportation service to all transportation customers on a non-discriminatory basis.

Northern States argues that the Commission erred by limiting required no-notice service to bundled, city-gate, firm sales customers under contract as of May 18, 1992. Northern States argues that it is necessary to offer no-notice service to all firm shippers to eliminate undue discrimination between classes of service. Prior Energy similarly argues that pipelines should be required to offer no-notice service to all shippers who wish to purchase it on an open access, non-discriminatory basis. Prior Energy contends this is necessary to avoid discrimination between customers by allowing customers who were also customers on May 18, 1992, to receive a service unavailable to anyone else.

The APGA also argues that the Commission erred in limiting required no-notice service to customers that were entitled to receive no-notice firm city-gate sales service on May 18, 1992. The APGA argues that other customers should be entitled to no-notice service, "subject to (1) the rights of pre-existing bundled sales customers and (2) limitation of facilities."[106] The APGA maintains that this is necessary because some customers may have declined more firm sales service because of the high cost of supplies or because facilities may have been completed but not approved. The APGA adds that this restriction may undermine the growth in the natural gas industry because LDCs will not be able to render incremental service on a reliable basis. The APGA maintains that a pipeline should bear a heavy burden of showing that it cannot provide incremental no-notice service because it lacks operational flexibility.

Southwest Gas and Indicated UtiliCorp Divisions argue that no-notice service should be offered to customers who previously converted to transportation to ensure comparability of service as envisioned by Order No. 436's policy that the quality and priority of service to a converting customer would be no lower than the quality of the prior sales service. [107]

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106. Petition at 7.

107. Southwest Gas cites Order No. 436, FERC Stats. & Regs. [Regulations Preambles] ¶ 30,665 at p. 31,517 (1985):

> Firm sales customers that convert their contract demand rights to transportation rights. . . will have the same priority of service under their converted transportation service as they did under their firm sales service agreements. There is no change in the quality

(Cont'd)

Southwest Gas adds that the Commission has arbitrarily changed its comparability policy which was reflected in the Commission's reliance on comparability in proposing this rule and in adopting no-notice service. It further argues that, in converting, customers relied upon continuation of the comparability principle to ensure no service degradation and that, on some pipelines (*e.g.*, El Paso Natural Gas Company), comparability concerns were yet to be resolved. Last, it maintains that reliability of unbundled transportation service via no-notice service is just as important to customers who converted prior to May 18, 1992.

The Commission denies rehearing. The Commission established the no-notice transportation service so that bundled, city-gate, firm sales customers can continue to receive service of the same reliability and quality in the unbundled environment as they received in the bundled environment. The Commission did not require pipelines to expand the eligibility for the no-notice transportation beyond those sales customers receiving no-notice service on May 18, 1992, for several reasons. First, because a stand-alone, no-notice transportation service is a new service, it is prudent to preserve only the status quo to allow pipelines to gain experience with its operation. Second, customers who were not receiving no-notice service (as part of their bundled sales service) on May 18, 1992, were not relying on that service because pipelines did not offer a no-notice transportation service. Third, those customers could not reasonably expect to receive no-notice service in the future. Order No. 436's requirement of service comparability, while broad, did not encompass no-notice firm transportation. Hence,

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(Cont'd)

or priority of their service, because the priority of their claim on the pipeline's capacity is unchanged by conversion.

the Commission did not change its comparability policy to the detriment of customers who converted prior to May 18, 1992. In addition, the Commission's Notice of Proposed Rulemaking (NOPR) did not explicitly propose no-notice transportation service. That service was required for bundled, city-gate, firm sales customers in the final rule in response to the comments to the NOPR and related technical conference held on January 22, 1992.[108] To conclude, the Commission required no-notice transportation service in response to a particular problem raised by petitioners *vis a vis* a particular service — no-notice bundled, city-gate, firm sales service. Nonetheless, the Commission strongly encourages the pipelines to make no-notice transportation service available to customers on a non-discriminatory basis to the maximum extent possible.

2. One-Time Election

In Order No. 636-A, the Commission concluded that pipeline sales customers have a one-time right to elect no-notice transportation during the restructuring proceeding. The APGA argues that this limitation is untenable because the pipeline's customers cannot make their decisions without knowledge of the Commission approved criteria and rates of no-notice service and without some practical experience. The APGA seeks clarification that "(1) a pipeline shall not require a binding and permanent election of no-notice service until after the pipeline's tariffs are made effective following restructuring; (2) customers electing no-notice service may alter their nominations prospectively under procedures set forth in the tariff."[109]

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108. Order No. 636 at pp. 30,408-09.

109. Petition at 9.

Similarly, the regulatory commissions of the states of Iowa, Missouri, and Wisconsin argue that it is impossible for LDCs to elect no-notice service until the Commission rules on the pipeline's compliance filing. They argue that the Commission should allow the free availability of no-notice service until system users have the experience to make informed choices.

The Commission continues to believe that the right to elect no-notice transportation must be exercised in the restructuring proceedings. The Commission recognizes that final elections on the precise levels of no-notice service may depend on the Commission's final disposition of the compliance filing, so that the final elections may need to be made after the Commission's order accepting the compliance filing. The Commission, however, will not require pipelines to provide the ability to elect new or added no-notice service after the effective date of restructuring. The purpose of no-notice transportation is to provide former bundled sales customers with continuity of service upon the effective date of the pipeline's compliance filing. Pipelines may, if they wish, permit their customers to switch between no-notice and other transportation services after the restructuring proceedings so long as this ability is available on a nondiscriminatory basis. The pipeline and the customer would execute a new contract for the different service and they would terminate the contract for the previous service. This is similar to the requirement that if a pipeline voluntarily offers no-notice service in the restructuring proceeding to customers other than those who qualify under the rule, it must do so on a non-discriminatory basis.[110]

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110. Order No. 636-A at p. 30,574.

Appendix D

3. Upstream Pipeline and Other Deliveries

The APGA and AGD ask the Commission to clarify that upstream pipelines will be required to provide a no-notice transportation service at the downstream pipeline delivery point. The APGA maintains that customers that qualify for no-notice service on downstream pipelines must be offered no-notice service on upstream pipelines, even if they have no direct customers that qualify for the service.

The Commission clarifies that upstream pipelines need to provide no-notice transportation service only to those customers to whom they provided no-notice service on May 18, 1992, and to the capacity assignees of those customers under section 284.242 of the Commission's regulations.[111] This is because it is reasonable to assume that a downstream pipeline that provided no-notice service without no-notice service from upstream pipelines can continue to provide no-notice service without requiring the upstream pipeline to serve the downstream customers on a no-notice basis. In short, the assignees of the downstream pipeline step into its shoes for this purpose when they take the capacity on the upstream pipeline.

New Jersey Natural contends that if a customer received firm no-notice sales service at a place other than its city gate, it should be entitled to receive no-notice transportation.

The Commission clarifies that an upstream pipeline that provided a no-notice sales service on May 18, 1992, to a

111. See Order No. 636-A at pp. 30,572-73, where the Commission's description of no-notice service to downstream customers assumes that they can succeed to any no-notice service held by the downstream pipeline on upstream pipelines.

customer that did not take delivery at its city gate must provide no-notice transportation to that customer at the non-city gate delivery point. This comports with the Commission's conclusion that customers receiving no-notice service on that date should have the right to maintain the no-notice aspect of their service. The Commission discussed no-notice service in the context of citygate service because that was the predominant no-notice service.

Brooklyn Union argues that it should be entitled to no-notice transportation regardless of whether it took its sales gas at its city gate from the selling pipeline or through an intermediary pipeline. It states that it purchases gas from certain pipelines that are not connected to its city gate with other pipelines transporting the gas to its city gate. It cites as an example its purchases from CNG Transmission Corporation that are delivered to Brooklyn Union's city gate by Transco and by Texas Eastern Transmission Corporation. UGI notes its concern that it cannot become a no-notice transportation customer on the upstream pipeline in lieu of the no-notice sales service it receives from Columbia Gas. UGI takes the Columbia Gas directly from Texas Eastern.

With respect to the scenario described by Brooklyn and UGI, where each bought gas from one pipeline but took delivery from another pipeline, the Commission interprets no-notice to mean that Brooklyn Union and UGI are entitled to no-notice service from the delivering pipeline (*i.e.*, Transco and Texas Eastern), if the delivering pipeline was contractually obligated to deliver the gas to them on a no-notice basis on May 18, 1992. However, whether Brooklyn Union or UGI is entitled to no-notice service on an upstream pipeline (*e.g.*, CNG) is an issue for the restructuring proceeding.

4. Option to Elect No-Notice or Traditional Transportation Service

In Order No. 636-A, the Commission concluded that "a sales customer, at its election during the restructuring proceeding, may choose no-notice or traditional firm transportation or a combination of the two."[112] CIG argues that the Commission erred by permitting former bundled sales service customers to choose their transportation services. CIG maintains that while the Commission recognized that no-notice transportation service was the appropriate substitute service for bundled sales service, it did not show that the firm transportation option is needed on all pipelines. CIG claims that this option is peripheral to the problem faced by the Commission and, therefore, improper.[113] In addition, CIG contends that it will lose the needed centralized coordination and control of its system if customers are permitted to elect traditional firm transportation service. It maintains that traditional firm transportation customers might adversely affect its system capacity, storage operations, gathering system, the thermal content of its gas, and transition costs. It asks the Commission to eliminate the traditional firm transportation option or alternatively reaffirm that pipelines can condition that service in a way that ensures operational control.

The Commission's intent in the instant rule is to afford former bundled sales customers a meaningful choice of transportation services best suited to their needs. In addition, no-notice service was established as an additional, or enhanced, form of firm transportation service and not as a service in lieu

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112. Order No. 636-A at p. 30,577.

113. *Citing* Associated Gas Distributors v. FERC, 824 F.2d 981, 1018-20 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

of traditional open access firm transportation service. Hence, while the Commission improved traditional open access firm transportation service (*e.g.*, storage and flexible delivery points), the Commission intended no-notice transportation service as an additional transportation option for no-notice sales customers.

The Commission reaffirms that pipelines may need to impose operational conditions on traditional open access firm transportation to perform no-notice transportation. The pipelines, of course, must propose those conditions in their compliance filings so that the Commission can evaluate them to determine if they are reasonable operational conditions under sections 284.8(c) to be applied without discrimination as required by section 284.8(b).[114]

5. Flexible Delivery Points

In Order No. 636-A, the Commission stated that pipelines must provide their no-notice transportation service at flexible delivery points. United argues that the Commission should eliminate this requirement because it will result in inefficient usage of the pipeline system and result in greater costs for no-notice shippers.[115] It adds that this requirement goes beyond the Commission's justification for no-notice service and the Commission's NGA section 5 authority to modify unreasonable contracts. It argues that the Commission has mandated a service clearly superior to the bundled, no-notice, firm city-gate, sales service provided on May 18, 1992. United

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114. See also the discussion of operational control in the discussion of storage, *infra*, Part E.2.

115. United refers to the cost of transmission and storage capacity reserved by it to provide no-notice delivery at any delivery point.

concludes that no-notice service beyond the delivery points specified on May 18, 1992, should be optional on a non-discriminatory basis.

Upon further reflection, the Commission will further clarify its position on the availability of flexible delivery points for no-notice service. Because no-notice service is limited to a discrete set of former sales customers and is intended to duplicate service provided under the pipeline's bundled sales service, a pipeline will not be required to provide flexible delivery points for its obligation to provide transportation, on a no-notice basis, without scheduling penalties. In other words, pipeline customers are entitled to no-notice service at their primary firm delivery points at the time they convert from bundled sales service to no-notice transportation service. The pipeline customers are not limited to their delivery points as of May 18, 1992. For example, a pipeline sales customer with delivery points A, B, and C pre-restructuring will retain those delivery points post-restructuring for no-notice service but will not be entitled to receive no-notice service at other primary firm delivery points or at secondary firm delivery points. Pipelines are free, however, to provide for flexible delivery points for no-notice service when operationally feasible.

One of the primary reasons the Commission required the provision of flexible delivery points was to facilitate capacity release of firm transportation capacity. No-notice service is a firm transportation service under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty. No-notice service, therefore, consists of two aspects: firm transportation and no-notice delivery. The releasing shipper can release its firm transportation capacity with the right to flexible delivery points. However, the no-notice

delivery aspect of its service pertains only to current delivery points as described above and not to flexible delivery points, which are part of the firm transportation aspect of its service.

6. Operational Flow Orders

In Order No. 636, the Commission stated that "pipelines have the right to impose reasonable operational conditions and to issue, on a non-discriminatory basis, operational flow orders without liability, except for negligence or undue discrimination, to be able to provide a no-notice transportation service."[116] New Jersey Natural asks the Commission to clarify that pipelines may not use operational flow orders to impose "must take" requirements on its customers. It maintains that "must take" requirements will subvert the efficiency goal of a competitive market if customers must take gas regardless of economic and market conditions. It adds that they may not be able to physically take the gas and that unmarketable gas would increase costs to their ratepayers and could harm their markets in the long run. It further contends that operational flow orders might require LDCs to take gas above their contractual obligations to pipelines and might undermine no-notice service by requiring LDCs to take gas instead of reducing takes below the nominated volumes without notice.

A pipeline may not issue an operational flow order that would require a shipper to ship gas above its reservation quantity. However, the Commission reaffirms that pipelines are entitled to impose reasonable operational conditions, including operational flow orders. The pipeline, therefore, can make its shippers inject gas into the system within their contract

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116. Order No. 636-A at p. 30,575.

quantities ("must ship" gas) when and where necessary to maintain the system's operational integrity and to enable the pipeline to provide no-notice transportation service. The Commission, as stated, will review the conditions proposed by pipelines to ensure they are reasonable and are nondiscriminatory. In addition, as no-notice service evolves, and experience is gained, the Commission expects to revisit the conditions in light of that experience. In particular restructuring compliance filings, the Commission will consider arguments that particular conditions are unworkable with respect to particular pipeline customers.

E. Storage

In Order No. 636, the Commission amended section 284.1(a) of the Commission's open access regulations to define transportation as including storage. This section deals with petitioners' contentions about allocation of the open-access storage capacity and the rights of existing holders of storage capacity.[117]

1. Allocation Of Downstream Storage Capacity

In Order No. 636-A, the Commission clarified Order No. 636 by stating that current bundled firm sales customers have a priority right to the storage necessary to maintain their level of maximum daily entitlement to service whether or not they elect no-notice transportation service. The Commission further stated that previously converted customers are not entitled to the same priority as customers converting under Order No. 636-A because

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117. Transco's request for clarification regarding unbundling at the outlet side of its Eminence storage field is an issue for its restructuring proceeding.

the former customers were able to convert without storage to meet their needs. In addition, the Commission stated that current system users are to have no priority over new transportation customers for any storage capacity available after converting customers exercise their priority right to storage.

The Indicated UtiliCorp Divisions argue that the Commission erred in denying guaranteed access to storage for previously converted sales customers. It argues that pipelines (such as Williams Natural Gas Company) used their storage to support their transportation customers on peak days and included storage costs in their firm transportation rate. It asks the Commission to clarify that, "unless a former sales customer expressly has relinquished its right to system storage capacity upon exercise of its conversion rights, it retains a priority right to that capacity."[118] It adds that the relinquishment issue should be left to individual restructuring proceedings.

The United Cities also argue that LDCs that previously converted to firm transportation should have priority rights to pipeline storage facilities. United Cities maintain that those customers have used the storage bundled within pipeline sales to meet swings in demand above their firm transportation base load. United Cities add that providing certain customers with "artificially high" pipeline storage capacity will cause the pipeline to operate below maximum efficiency. They claim this is so because those customers will use storage for the middle of their load profile, thereby reducing peak withdrawals.

Prior Energy objects to the priority for converting sales customers on the grounds that they may not value it as highly

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118. Petition at 7.

as other shippers, such as marketers. Prior Energy maintains that Order No. 636-A thwarts the goal of vigorous competition by relegating non-sales customers to a second-tier of storage claimants.

The Commission reaffirms its clarification in Order No. 636-A that only current bundled firm sales customers have a priority right to storage. Customers that have previously converted to firm transportation under Part 284 without contract storage are not entitled to a priority because they were able to receive their firm transportation entitlement level without any contract storage rights. A pipeline's use of system storage to support transportation service, and the allocation of storage costs to transportation, was not related to firm entitlement levels, but to operational management and balancing.[119] Pipelines may continue to reserve some amount of system storage for operational management and balancing to support traditional transportation services to customers, including previously converted customers, as well as no-notice transportation. The pipeline has the burden of showing what level of storage it needs to support its services.

The Commission's grant of priority to bundled sales customers to preserve service levels is necessary to ensure their certificated levels of service. "Value of service" concepts are not pertinent to this priority right to the storage.

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119. System storage includes facilities owned and used by the pipeline to store its own gas for operational reasons such as for balancing. System storage also has been used in lieu of transportation capacity to make bundled sales.

Appendix D

2. Existing Contract Storage Service

In Order No. 636-A, the Commission concluded that while current contract storage customers retain their full right to capacity as specified in their contracts, the terms and conditions associated with those rights could be changed, if they are unreasonable in light of Order No. 636's requirements of no-notice transportation and open access contract storage.[120]

AGD, Brooklyn Union, PSE&G, and UGI argue that the Commission has not justified why it is necessary to affect existing storage arrangements.[121] AGD contends that the Commission has offered no explanation about why a pipeline cannot use the same physical and operational assets that it uses to render no-notice sales service to provide no-notice transportation service. AGD, PSE&G, Brooklyn Union, and UGI maintain that a reduction in the quality of currently certificated contract storage could jeopardize an LDC's ability to serve its customers during peak periods. They ask the Commission to state that it will not permit changes to their contract storage service quality, such as adverse modifications to existing contract storage capacity and injection or withdrawal schedules. AGD and PSE&G maintain that any such degradation of service would be a *de facto* abandonment and would be inconsistent with the abandonment requirements of NGA section 7(b).

The Commission clarifies that, while it has authorized pipelines to propose to change existing storage arrangements,

120. Contract storage describes storage capacity with respect to which the customer can inject its own gas.

121. AGD and UGI argue similarly with respect to existing transportation service.

if necessary, to provide no-notice transportation service, the pipeline must still show that the changes are necessary and reasonable. This includes an analysis of the impact of a change on current contract storage customers. The Commission has not authorized any reduction in contract storage capacity. The Commission views changes to injection and withdrawal schedules as changes to terms and conditions, rather than changes to the level of certificated service. Hence, the Commission concludes that changes to existing contract storage terms and conditions will not need action under NGA section 7(b).[122]

F. Market Centers/Pooling Areas

In Order No. 636, the Commission adopted sections 284.8(5) and 284.9(5), which prohibit tariff provisions that inhibit the development of market centers. The Producer Associations, as a progress report, allege that long-line pipelines are proposing rate features that will make it uneconomical for gas suppliers attached to those pipelines to switch pipelines at a market center to serve markets on a different pipeline. They cite the following examples:

> Rate features such as "system access charges," a requirement that firm mainline transportation must be supplied by firm production-area transportation contracts, and GSR surcharges applicable to production-area transportation make it very difficult and expensive for gas suppliers to access markets through transportation on multiple pipelines.

122. The pipelines may change the terms and conditions of other services in a similar manner, if necessary to provide no-notice transportation.

> In addition, permitting pipelines to charge their forward haul rates for backhaul service has, on several pipelines, insulated markets from competition by off-system suppliers. Further, several pipelines have proposed transportation rates based upon the zone of the delivery point, irrespective of the length of haul. Such tariffs also have the effect of discouraging competition.[123]

NERCO contends that pipelines are developing proposals that limit pipeline-to-pipeline competition in the supply area and inhibit the creation of market centers and commercially useful pooling points. NERCO cites as an example the implementation of production area rates that are too low and the definition of access area to the mainline to include inputs that should be outside the area. NERCO asks the Commission to clarify on rehearing that "individual pipelines may not, in the course of the restructuring proceedings, implement production area rates and other onerous proposals that inhibit pipeline-to-pipeline production area competition and, thus, inhibit the creation of market centers and commercially useful pooling points."[124]

The Commission reemphasizes that pipelines may not implement rates (or terms and conditions of service) that inhibit the creation and development of pooling areas and market centers.

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123. Petition at 2, 3.

124. Petition at 14, 15. ConEd endorses NERCO's request.

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Market centers are areas where a) pipelines interconnect and b) there is a reasonable potential for developing a market institution that facilitates the free interchange of gas. The size of a given market center may depend on the specific configuration of the pipelines involved. However, the Commission expects generally that market centers should normally be fairly small — for instance, a 30-mile radius around a central point. In order to facilitate gas transactions, many market centers are likely to offer services that correct imbalances among pipelines (for instance, through storage).[125]

Rate structures can inhibit market centers when (for instance) they require shippers to pay for substantial amounts of capacity both upstream and downstream of a market center in order to use only the upstream or downstream part of the pipeline. Postage stamp rates and rates based on large zones can have this effect. Similarly, rates can inhibit market centers when a pipeline charges a large zone rate simply to transfer gas among two other nearby pipelines within a market center. In both cases, the result amounts to tying transportation services together that are commercially distinct and is contrary to the spirit of service unbundling. In addition, inappropriate rates for backhauls or penalties for scheduling and balancing can inhibit market center development. Either can prevent a shipper from using its capacity rights flexibly and inhibit the flexible commercial interchange of natural gas.

The Commission does not require pipelines to adopt any particular approach to ensure that they do not inhibit the

125. See, for example, illustrations of market centers in Importance of Market Centers, Office of Economic Policy, FERC (Washington, D.C.), August 21, 1992.

development of market centers.[126] However, the Commission reiterates that the effects of pipeline rates and terms and conditions of service on market centers and pooling areas should be resolved in individual restructuring proceedings.[127]

G. Flexible Receipt and Delivery Points

1. Small Customers

Prior Energy asks the Commission to clarify whether small customers are entitled to use flexible receipt and delivery points. Small customers are firm shippers under Part 284 of the Commission's regulations and therefore are entitled to flexible receipt and delivery points just as any other Part 284 firm shipper. Flexible delivery points, however, are of primary importance to facilitate capacity releasing. Since small customers paying one-part rates are not able to release capacity, the availability of flexible delivery points may be of only minimal value to them.

2. Penalties

In Order No. 636-A, the Commission concluded that "[i]ssues involving provisions governing the use of receipt and delivery points, including appropriate penalties, must be

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126. Depending on the pipeline configuration and operation, it may be possible, for example, to establish special zones for market centers, small zones or rates based on 100 mile increments, or separate "within market center" rates for hauls to and from interconnections within larger zones.

127. *See, e.g.*, El Paso Natural Gas Co., 60 FERC ¶ 61,109 (1992).

addressed in the restructuring proceedings."[128] The Commission added that "there must be some valid operational reason for imposing penalties on changes in volumes to delivery points within an interrelated service area."[129]

The Fuel Managers Association is concerned about unduly strict scheduling requirements and scheduling penalties. It asks the Commission to clarify that a pipeline must demonstrate affirmatively, through documented evidence submitted during the restructuring proceeding, that any proposed scheduling requirement or penalty mechanism is needed to address operational concerns on its system and why a less onerous scheduling requirement or penalty would not be sufficient to address its operational concerns. It maintains that a mere statement by a pipeline that it needs its scheduling requirements or penalties to inhibit abusive behavior should not satisfy its burden of proof.

The Commission grants the Fuel Manager Association's clarification and agrees that pipelines must demonstrate that their proposed scheduling requirements and penalty mechanisms are reasonable operational conditions. The Commission observes that scheduling requirements and penalties serve different functions. Scheduling requirements are needed to provide the pipeline with advance information to operate its system efficiently. Penalties are designed to inhibit behavior inimical to the operational integrity of a pipeline system.

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128. Order No. 636-A at p. 30,584.

129. *Id.*

Appendix D

3. Deliveries Within a Zone

In Order No. 636-A, the Commission concluded as follows with respect to alternate flexible delivery points within a zone:

> [S]hippers with upstream delivery points within a zone can select downstream delivery points within the same zone and . . . operational concerns can be met by making service to the downstream delivery point interruptible. This is consistent with the general principle that controls here: a shipper gets flexibility in receipt and delivery points for the part of the system for which it pays a reservation charge. Thus, if a pipeline has zone rates, a shipper gets flexibility within its zone.[130]

New Jersey Natural argues that the alternate flexible firm delivery points downstream in a zone should have priority over the rights of interruptible shippers. It also seeks clarification that shippers on pipelines with postage-stamp transportation rates may designate downstream delivery points without restriction. It maintains that they should be able to do that because both upstream and downstream shippers are paying for access to the entire pipeline system.

The Commission's discussion, quoted above, was addressed to the relative rights only of firm shippers. Firm shippers with alternate flexible firm delivery points downstream in a zone have priority over the rights of interruptible shippers but not

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130. Order No. 636-A at p. 30,585.

over firm shippers with primary firm delivery points. Shippers nominating volumes for delivery to primary firm delivery points have scheduling priority over shippers nominating volumes for flexible (alternate) firm delivery points.

With respect to designation of downstream flexible delivery points, a postage-stamp system should be treated similarly to a zone system. Since shippers on a system with postage-stamp rates pay reservation charges covering the entire system, they may designate downstream alternative firm delivery points on the same basis as shippers within a zone. The Commission strongly encourages pipelines with postage stamp rates to consider developing smaller zones or mileage-based rates, particularly where such rate structures will foster the development of market centers.

4. Curtailments

The APGA seeks clarification with respect to the scenario where there is a capacity constraint in the path of firm transportation on behalf of shippers using primary and flexible delivery points. It maintains that since the service to alternate delivery points is interruptible, it should be curtailed prior to service to any primary delivery point.[131] It adds that this should be so whether the alternate delivery point is upstream or downstream of the primary delivery point.

The Commission clarifies that a pipeline must give

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131. The firm shipper selects primary delivery points, which are firm for scheduling purposes, and secondary or alternate delivery points, which do not have scheduling priority over primary delivery points of other firm shippers but have scheduling priority over delivery points of interruptible shippers.

scheduling priority to shippers using primary delivery points if there is a capacity constraint when, for example, a compressor is malfunctioning. That is, the shipper scheduling for an alternate firm delivery point is treated as interruptible for scheduling purposes in this situation.[132] If the constraint develops after gas is scheduled, service to alternate firm delivery points should be considered just as firm as service to primary firm delivery points.

V. Transportation Rates

In Order Nos. 636 and 636-A, the Commission adopted the SFV method of cost classification for cost allocation and rate design (billing) purposes, required the use of different measures to mitigate cost shifts, and required pipelines to continue to serve small customers at a one-part rate computed using an imputed load factor. Petitioners raise a variety of issues with respect to the mitigation measures and the treatment of small customers.

A. Different Ratemaking Techniques

In Order No. 636-A, the Commission stated that "it will require the parties to use different ratemaking techniques in connection with the distribution of revenue responsibility among customers to avoid significant cost shifting that may result from the elimination of the two-part demand charge or the allocation of costs based on peak day demand."[133] The Commission strongly encouraged the use of seasonal contract quantities (*i.e.*,

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132. Scheduling service at the alternate firm delivery points is, of course, superior to scheduling interruptible transportation. Order No. 636 at p. 30,583.

133. Order No. 636-A at p. 30,599.

seasonal entitlements or CDs) as a means to counteract those shifts and as a replication, in part, of the allocation of costs based on peak and annual considerations. The Commission permitted the parties to explore other methods.

1. Opposition to Different Ratemaking Techniques

Several petitioners oppose the use of different ratemaking techniques to mitigate significant cost shifts. In particular, they oppose the use of seasonal contract quantities or annual volumes as the mitigation technique.

Allied-Signal objects to the using of different ratemaking techniques to avoid significant cost shifts owing to SFV because in its view the customer class phase-in method, the capacity adjustment and releasing mechanisms, and the use of a one-part volumetric rate at an imputed load factor for small customers provide all the mitigation necessary. The Industrial Groups similarly argue that firm customers can mitigate via capacity releasing and alternatives such as peak shaving, storage, and conservation.

The Commission believes that the Order No. 636-A mitigation measure is superior to the methods referred to by Allied-Signal. It is broader based than the treatment afforded small customers and historic customer classes in that it mitigates for all customers which face a significant cost shift. Moreover, it ensures mitigation as part of the ratemaking process rather than relying solely on the possibility that capacity can be released or other measures implemented. Finally, the Commission in the past has used ratemaking approaches (such as imputed load factors and annual nominations) that recognized that customer load factors vary.

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Allied-Signal, the Industrial Groups, Sierra Pacific, Louisville, and LILCO maintain that the use of seasonal contract quantities or techniques based on annual volumes will have a variety of undesirable impacts. For example, they argue that such mitigative techniques will be inefficient with respect to such matters as customer load factors, patterns of pipeline usage, storage acquisition and use, and capacity releasing. The Commission concludes it is premature to speculate as to the generic impact of seasonal contract quantities or other mitigation measures. Petitioners may raise their contentions about impact in specific restructuring proceedings when the issue is joined, and where arguments can be linked to the specific circumstances of the pipeline and its particular customers.

The Industrial Groups argue that the end result of mitigation is a welfare-type subsidy for low load factor customers while Louisville argues that seasonal contract quantities are an inequitable subsidy because they hurt residential customers of LDCs who have undertaken load factor improvement efforts. The Commission believes it is appropriate to minimize significant cost shifting that may occur among customers so that the impact of SFV, to aid competition as discussed in Order Nos. 636 and 636-A, is not distributed inequitably among the shippers on the interstate pipeline network. The Commission does not consider this to be an unfair "subsidy," because it does no more than maintain the status quo with respect to the relative distribution of revenue responsibility.

The Industrial Groups and Allied-Signal maintain that seasonal contract quantities will undermine or distort SFV's price signals. Sierra argues that seasonal contract quantities undermine the Commission's goals in that they will improperly affect a gas customer's choice about its gas seller. It maintains

that this will result because the demand charges on different pipelines will be determined based on seasonal demands. It points out that on pipelines with identical costs the demand charges will differ because they have a difference in seasonal demand.

The Commission sees no adverse impact on price signals or improper impact on a gas purchaser's choice of gas sellers stemming from the use of seasonal contract quantities or similar measures because the pipeline's reservation charge will still be billed under the SFV method. In addition, that seasonal contract quantities will produce different reservation charges on pipelines with identical costs is a fact entitled to no weight. That situation is just as likely to occur without seasonal contract quantities because it is unlikely that two pipelines would have identical reservation quantities with daily reservation quantities applicable throughout the year. In addition, it is highly unlikely that any two pipelines would have identical costs.

Sierra further argues that this mitigation approach is inconsistent with Commission policy that transportation rates are to reflect allocative and productive efficiency. It maintains this is because seasonal contract quantities encourage demand on peak days and penalize off peak use.

The Commission did not adopt SFV to promote allocative and productive efficiency in the use of pipeline capacity.[134] Rather, it adopted SFV, as fully discussed in Order Nos. 636 and 636-A, to promote the goal of an efficient, national gas market by allowing all gas merchants to compete equally without regard to fixed transportation costs included in the pipeline's

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134. Order No. 636-A at p. 30,605.

usage charge. The Commission's decision to require pipelines to implement ratemaking techniques to eliminate cost shifts resulting from the change to SFV does not interfere with this goal because the usage charge for firm transportation would be unaffected by any such ratemaking techniques. In any event, the lower usage charge under SFV should enhance productive efficiency by promoting gas on gas competition, reducing transportation usage rates and encouraging increased throughput.

Sierra maintains that, in effect, there is no difference between the D-2 charge and seasonal contract quantities. It adds that seasonal contract quantities reintroduce the problems associated with D-2s, such as how they are chosen and whether renominations will be allowed. It argues that Order No. 636-A makes implementation problems more severe by making it difficult to predict needs. It also maintains it is unclear what effect a customer's seasonal contract quantity will have on the pipeline's certificate obligation.

Seasonal contract quantities are different from, and in the Commission's judgment, superior to the manner in which D-2 charges operated. D-2s did not reduce the firm customer's daily entitlement, while seasonal contract quantities do place a contractual limit on capacity rights. D-2s also did not permit the pipeline to sell unsubscribed firm off-peak capacity, while seasonal contract quantities would permit such sales of unsubscribed off-peak firm capacity. The Commission believes that the issue of how seasonal contract quantities are chosen is an issue for the restructuring proceedings.[135] As with no-notice

135. That is, pipeline customers do not have a unilateral right to seasonal contract quantities. However, a pipeline that does not want to have seasonal contract quantities must develop another methodology to address potential significant cost shifts, as discussed in Order No. 636-A.

service, this election should be made during the restructuring proceedings. Pregranted abandonment under section 284.221(d) of the Commission's regulations is granted to the extent there are reduced seasonal quantities. The parties to the restructuring proceedings should address the issue of whether shippers should have renomination rights after a pipeline's restructuring becomes effective.

LILCO maintains that seasonal contract quantities will enable pipelines to collect excess revenues associated with uncommitted capacity from which it can collect interruptible transportation revenues. The Commission sees the interruptible revenue issue raised by LILCO as no different than the allocation of costs to interruptible service ordinarily faced by the Commission.[136]

Sierra argues that the use of seasonal contract quantities is merely a cost-shift mechanism that has no relationship to how costs are incurred. The Industrial Groups argue that facilities are built to meet peak demands and that off peak usage adds only variable costs. Hence, they maintain, any technique based on annual factors would allow customers to escape cost responsibility.

The Commission stated in Order No. 636-A that it adopted SFV because the pro-competitive goals to be accomplished via SFV generally outweigh the ratemaking principle of allocating fixed costs to annual throughput. However, the Commission required adjustments in connection with the distribution of revenue responsibility among customers to avoid significant

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136. See the discussion of this issue in the capacity releasing part of this order, *supra*.

cost shifts among pipeline customers resulting from varying load profiles.

The Commission believes it is appropriate to recommend the use of seasonal contract quantities to mitigate significant costs shifts that may occur in individual cases because the use of annual or similar factors is a well-settled method of distributing revenue responsibility among pipeline customers that will not conflict with the goals to be achieved via SFV by retention of a one-part reservation charge for billing purposes.

Southwest Gas asks the Commission to clarify that (except for two-part demand charges) it will permit any variety of either entitlement-based allocation methods (*e.g.*, seasonal or maximum daily entitlements) or demand-based allocation methods (*e.g.*, coincident peak demand). At this time, the Commission is not prohibiting any particular techniques except, as discussed below, that two-part demand charges may not be used for billing purposes.

Southwest Gas seeks clarification about whether allocation methods to reduce cost shifting are to be applied uniformly to all customers. Since the extent of cost shifting and the application of any ratemaking technique is dependent on the circumstances facing each pipeline, the Commission cannot make a generic determination of this issue. Parties in the individual restructuring proceedings should consider and develop the ratemaking methodology best suited to reducing the cost shifts for each pipeline.

To conclude, the Commission adheres to its conclusion that pipelines must "use different ratemaking techniques in connection with the distribution of revenue responsibility among

customers to avoid significant cost shifting that may result from the elimination of the two-part demand charge or the allocation of costs based on peak day demand."[137] The Commission believes it is appropriate to "minimize significant cost shifting" among customers,[138] so that the impact of adopting SFV to aid competition as discussed in Order Nos. 636 and 636-A is not distributed inequitably among the shippers of varying load profiles on the interstate pipeline network. The Commission also continues to strongly encourage the use of seasonal contract quantities to mitigate significant cost shifts that may occur owing to the adoption of SFV. However, the Commission recognizes that it may not be appropriate in all circumstances to use seasonal contract quantities and encourages creativity in the tailoring of mitigation techniques suited to the specific facts of each case. Hence, the Commission will not, as requested by the APGA, adopt a presumption favoring the use of seasonal contract quantities.

2. Meaning of Significant Cost Shifts

Several petitioners ask the Commission to define significant cost shifting. Allied-Signal maintains that at a minimum this means a ten percent or more rate impact of SFV on any customer class. The Industrial Groups would define a significant increase as over ten percent. The Producer Associations would also apply the 10 percent threshold. Sierra argues that all costs (transportation, storage, and gas costs) reflected in the delivery price of gas to the pipeline's customer must be considered.

The Commission clarifies that all transportation costs (*i.e.*,

137. Order No. 636-A at p. 30,599.

138. *Id.*

costs allocated to transmission, including system storage retained by the pipeline) are to be considered in applying the "significant" cost shift test.[139] The delivered cost of gas is irrelevant to the impact of SFV on a customer's transportation costs. In addition, this test is to be applied by customer rather by customer class.[140] However, the Commission declines to set a bright-line test for determining "significant" cost shifts because this depends heavily on the facts of each case. The only bright-line test occurs at the end of the restructuring ratemaking process when pipelines must phase-in cost shifts over no more than a four-year period, if the use of SFV, *after* implementation of other ratemaking techniques designed to minimize cost shifts, still results in a 10 percent or greater increase in revenue responsibility for any historic customer class.

Allied-Signal argues that the use of different ratemaking techniques should be used to mitigate the significant impact of SFV and not to eliminate all cost shifts by putting customers into the same revenue position as they were under MFV. Similarly the Fuel Managers Association contends that mitigation must not create cost shifting to high load factor customers by over-mitigating the cost shift to low load factor customers caused by SFV. The Commission clarifies its goal is

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139. In addition, if the pipeline used MFV to design its contract storage rates, it must determine if the use of SFV will result in a significant cost shift for existing contract storage customers. However, if the rate design for contract storage did not change, then it need not be included in determining whether significant cost shifts will occur.

140. Northwest Pipeline Corp. 61 FERC ¶ 61,165 (1992), United Gas Pipeline Co., 61 FERC ¶ 61,161 (1992), Alabama-Tennessee Natural Gas Co., 61 FERC ¶ 61,164 (1992), Mississippi River Transmission Corp., 61 FERC ¶ 61,163 (1992), and Pauite Pipeline Co., 61 FERC ¶ 61,162 (1992).

to avoid significant cost shifts resulting from the change to SFV and not to provide an opportunity for some customers to make themselves better off at the expense of other customers.

3. Phase-Out

The Industrial Groups contend that any ratemaking techniques used to avoid significant impacts should be phased out over the four-year transition period. Sierra also argues that these measures should be transitional, as were D-2s, and not permanent.

The Commission clarifies that there is to be no automatic phase-out period for any technique used to avoid potential significant shifts in the assignment of revenue responsibility. The Commission will examine the appropriateness of the assignment of revenue responsibility in future NGA section 4 or 5 cases. Customers can file complaints under NGA section 5 for Commission reconsideration of the lawfulness of effective rates and the underlying method for distributing the revenue requirement.

4. Seasonal Capacity Availability and Seasonal Rates

The Fuel Managers Association argues that pipelines must make available, on an open access basis, any seasonal firm capacity that becomes available through the use of seasonal contract quantities.

Similarly, Blue Flame argues that the pipelines should be able to offer services that take advantage of seasonal demands for gas from special use customers. Blue Flame maintains that the Commission should not have discouraged the creation of

customer classes, [141] which limits pipeline services to firm peak-day transportation, interruptible transportation and the small customer transportation services.

The Fuel Managers Association also argues that the Commission should clarify that the use of seasonal rates is particularly important to encourage the use of capacity in non-winter periods that becomes available because of the use of seasonal contract quantities. It is concerned that pipelines will have little incentive to discount rates if all costs are allocated to existing customers.

Sierra argues that any seasonal allocation to address shifts in revenue responsibility must reflect cost incurrence with costs classified between winter and summer seasons and then allocated based on seasonal demands to yield winter and summer reservation charges.

The Commission clarifies that it has put no limit on the current ability of pipelines to offer firm transportation service in any particular circumstance. Part 284 pipelines have always been and remain required to offer all firm capacity that becomes available. This will include capacity that becomes available through the use of seasonal contract quantities,[142] subject to any operational constraints.

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141. Blue Flame refers to the statement in Order No. 636-A that "as a general matter, the Commission discourages the creation of customer classes, other than the special small customer class provided for in this rule, or if necessary during the four year mitigation period." Order No. 636-A at p. 30,599-60.

142. *See* Northern Natural Gas Co., 61 FERC ¶ 61,079 (1992) (approving rate schedule under which shippers can transport on a seasonal basis).

The Commission will not require seasonal rates.[143] Seasonal rates are not related to the instant rule's goals or to the mitigation of significant cost shifts.[144] As indicated in Order No. 636-A, it may be appropriate to apply the principles enunciated in the Rate Design Policy Statement in determining whether seasonal rates are appropriate.[145] The Commission will consider the Fuel Managers Association's argument about the incentive to discount in connection with a particular case involving off-peak service.

5. Annual Allocation Measures

In Order No. 636-A, the Commission concluded that pipelines may not continue to use two-part reservation charges for either allocation or billing purposes.

The APGA asks the Commission to clarify that pipelines and their customers may use D-2 charges, if D-2s serve the purpose of distributing revenue responsibility among customers to avoid significant cost shifting. The APGA maintains that D-2s may be the best solution to cost shifting on certain pipelines.

CIG argues that a two-part demand charge does not undermine the Commission's policies in adopting SFV, because the charge is not based on usage but is assessed on the basis of peak entitlements regardless of actual volumes transported. CIG

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143. Seasonal entitlements differ from seasonal rates in that seasonal entitlements may yield one rate applicable throughput the year. See Order No. 636-A at p. 30,599 n. 308 for an example.

144. See Order No. 636-A at p. 30,606 with respect to cost incurrence and the instant rule.

145. *Id.* at p. 30,605.

adds that a two-part demand charge might be appropriate if a pipeline, like CIG, cannot provide maximum service entitlement levels throughout the year. It asserts that this would properly reflect cost incurrence. CIG further argues that a two-part reservation charge is consistent with the mitigation of cost shifts and is superior to seasonal contract quantities, because on its system temperature fluctuations occur throughout the year.

Southwest Gas argues that the Commission should permit D-2 charges because they are not a usage based charge. It adds that the end-result should determine the reasonableness of any approach.

The Commission concludes again that pipelines may not use two-part reservation charges for billing. It is true that the D-2 charge is not a usage charge in the sense that customers pay as they take service. However, the D-2 charge is similar to a usage charge in that the D-2 charge was to reflect demand for annual service in light of estimated use. In any event, the D-2 charge was derived, in part, to help pipelines in their role as merchants by enabling them to better estimate customers' annual gas purchases. In the competitive sales market with competitive pricing mechanisms for unbundled gas sales, which may include some type of gas inventory charge, the D-2 is no longer needed. Seasonal contract quantities also reflect the fact that a pipeline cannot provide maximum service levels throughout the year by allowing lower off-peak levels. That there are temperature fluctuations throughout the year does not militate against seasonal contract quantities. Rather, it suggests the use of monthly contract quantities, which the Commission encourages the parties to pursue in the restructuring, or subsequent, proceedings.

However, pipelines may use annual measures for cost allocation so long as only a one-part reservation charge is used for billing purposes. As stated in Order No. 636-A, the Commission will not foreclose the use of any annual measures as a vehicle for allocating revenue responsibility (*e.g.*, among rate zones) so long as the pipeline uses a one-part reservation charge for billing purposes and does not create different charges in the tariff for individual customers because of the use of D-2s or other annual allocation measures.[146] The Commission is permitting the use of annual measures because they may be the most appropriate method for certain cost allocations (*e.g.*, among rate zones) to avoid significant shifts of revenue responsibility.

Last, CIG states that its annual service limitations predate the Commission's adoption of the modified fixed variable method, have been negotiated based on operational constraints, and are incorporated in its certificates. Hence, it seeks clarification that the adoption of a one-part reservation charge does not affect its annual service limitations.

The Producer Associations argue that if the Commission allows fixed cost allocation based on D-2 nominations, customers should pay higher rates for taking deliveries over their nominations and should not be allowed to release capacity in excess of the nominated level. Similarly, Allied-Signal argues that, if annual volumes are used as a mitigation technique, there should be some restriction on the ability of a customer to demand service above its annual level without penalty.

The Commission clarifies that a pipeline may retain some form of annual service limitation post-restructuring in connection

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146. Order No. 636-A at p. 30,595 n. 287.

with a one-part reservation charge, as long as the annual service limitation does not operate as a D-2 charge. Furthermore, nothing in this rule obligates a pipeline to provide service in excess of its pre-restructuring certificate obligations. In any event, this issue is unrelated to the rate design issues addressed in Order No. 636.

6. Capacity Reduction

Meridian argues that SFV should only be adopted if the pipeline is capacity-constrained or full unless the customers are permitted to reduce or terminate their service unilaterally.

In Order Nos. 636 and 636-A, the Commission denied the right of customers to unilaterally reduce or terminate transportation service from the pipeline. The Commission also, as discussed in Order No. 636-A, did not apply the policy of adopting a rate design to ration capacity because in "the prevalent economic and market circumstances, . . . the goal of achieving an efficient, national gas market is the factor that should control the selection of appropriate rate design method."[147] Hence, Meridian's argument is rejected.

B. Rates for Small Customers

In Order No. 636-A, the Commission clarified that all pipelines that on May 18, 1992, offered a small customer sales or transportation rate service on a one-part volumetric basis at an imputed load factor rate must continue to offer firm and no-notice transportation services on the same basis. The

147. Order No. 636-A at p. 30,605. *See also* Order No. 636-A at pp. 30,637-38, where the Commission concludes that customers do not have the unilateral right to cost-free releases of capacity.

Commission also suggested pipelines should consider increasing the class of small customers by raising the eligibility level to up to 10,000 Mcf or Dth per day.

1. The Use of an Imputed Load Factor

Peoples Gas, the Northern Distributor Group, and Atlanta Gas argue that there is no basis for the Commission's requirement that pipelines continue indefinitely to offer small customers a one-part volumetric rate at an imputed load factor. They argue, among other things, that this results in two shippers paying different rates for the same service and is therefore discriminatory. They also argue it is unfair because large LDCs serve customers in poorer communities in large urban areas and serve communities that are smaller than the pipeline's small customers.

The Northern Distributor Group argues that, as provided in Order No. 636, imputed load factor rates for small customers should only be used as a transitional measure to be phased-out within four years. It asserts that this will adequately protect small customers against cost shifts. It also maintains that the use of imputed load factors results in a subsidy which does not serve equality or competitiveness. It adds that the requirement that the rate be changed only in an NGA section 4 or section 5 proceeding will have a chilling impact on changes because the burden will be on the proponent of change and that the pipeline will have little incentive to change the rate because it is recovering its costs. It concludes that either the rate should be negotiable in the restructuring proceedings or prior settlements should remain in effect. In that vein, it contends that a settlement

with Northern Natural Gas Company contemplated the eventual elimination of one-part rates.[148]

The Commission's aim with respect to service to small customers is to continue the status quo prior to the instant rule, subject to the few changes in terms and conditions adopted in this Rule. While some petitioners read Order No. 636 to mean that service to small customers at a one-part rate was to be continued only in connection with phased-out mitigation, that was not the Commission's intent. Arguments that the small customer rate should be discontinued should be raised in pipeline proceedings under NGA sections 4 or 5.[149]

On the other hand, the APGA argues that the Commission erred in failing to make the one-part rate design for small customers, as well as other ratemaking techniques employed to moderate the impact of SFV, a permanent rate design requirement for pipelines.[150] In the alternative, the APGA asks the Commission to rule that any changes to the one-part rate design can only be made prospectively under NGA section 5 rather than under NGA section 4, subject to refund.

The Northern Distributor Group argues that the use of a

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148. Northern Natural Gas Co., 53 FERC ¶ 61,207 at p. 61,835 (1990). The rate was for a three-year period ending September 30, 1993.

149. The Commission has, however, incorporated parts of pending proceedings with respect to rate design issues, which include one-part rate matters, into restructuring proceedings. Florida Gas Transmission Co., 61 FERC ¶ 61,019 (1992).

150. The temporal status of the other ratemaking techniques is discussed in other sections of this order.

small customer imputed load factor rate should be phased-out within four years.

As indicated above, the one-part rate design for small customers was continued because the Commission did not intend to change it in this rule. It is no more or less permanent than any rate design and may be changed under sections 4 and 5 of the NGA. Because the one-part rate design for small customers is a continuation of the status quo, it is not subject to phase-out under the instant rule.

2. Adjustments to Imputed Load Factor

In Order No. 636-A, the Commission stated that the pipeline's one-part, volumetric rate for its small customer service should be computed using the same imputed load factor as was used to compute its previous rate for its small customer sales service.

CIG seeks clarification that it can propose to adjust the imputed load factor to reflect changes in the load factor of small customers caused by Order No. 636. It maintains that this may be necessary to ensure that the imputed load factor does not substantially exceed the actual load factor.

The Gas Consumers argues that the Commission should require pipelines to derive their one-part rates using the system-wide load factor. It maintains that this is necessary to mitigate cost shifts, which is not done by using the class load factor. It asserts that a Commission mandate is sought because small customers lack the leverage to bargain for such a load factor.

The Northern Distributor Group argues that pipelines should

be allowed in their compliance filings to propose lowering their current imputed load factor for small customer rates.

As stated above, the Commission intends no change in its current policies with respect to the small customer rate.[151] This includes retention of the imputed load factor used to compute the rate for the small customer sales service unless there is warrant for increasing the imputed load factor as a measure to avoid shifts in revenue responsibility. However, the imputed load factor may not be decreased in the restructuring proceedings.[152]

3. Eligibility Date

In Order No. 636-A, the Commission required pipelines that, on May 18, 1992, offered a small customer sales or transportation service at a one-part volumetric rate, with an imputed load factor, to offer all of its firm transportation services on the same basis to eligible small customers.

The Gas Consumers argue that the Commission's justification for the use of one-part rates applies equally to all customers with peak capabilities of less than 10,000 Mcf per day, regardless of whether they were charged previously under one-part rates with imputed load factors. The Gas Consumers

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151. The only mandatory exception relates to restrictive criteria needed to ensure the pipeline has the opportunity to recover costs assigned to the small customer service. For example, the small customer must exhaust its daily level of firm entitlement before shipping gas under any interruptible transportation service available from the pipeline.

152. An exception would exist when the issue has been raised in a rate proceeding that has been incorporated into the restructuring proceeding. *E.g.*, Florida Gas Transmission Co., 61 FERC ¶ 61,019 (1992).

maintain that if the Commission grandfathers the one-part rate, it should do so with respect to all pipelines that ever offered service at a one-part rate to small customers, because many pipelines have replaced their one-part rates with two-part rates. Hence, it states, that, on May 18, 1992, most small customers that had received service under a one-part rate for years were receiving service under a two-part rate. The Northern Distributor Group argues that the small customer class should not be open to customers new to a pipeline system after May 18, 1992, to avoid further subsidies, which prevent unfair competition.

The Commission clarifies that, if a downstream pipeline offered service at a small customer rate on May 18, 1992, it must offer it to all customers directly connected to it who meet its eligibility criteria, even if such a customer was not a customer at that rate on May 18, 1992. The Commission's intent in Order No. 636-A was to grandfather service at the small customer rate to a particular class of customers and not particular customers.[153] That is, if the pipeline had a small customer rate schedule on May 18, 1992, it must retain that schedule and offer service thereunder to all customers who qualify. If a pipeline had discontinued all service at its small customer rate on May 18, 1992, and the Commission has approved of that discontinuation, it need not reinstate it because small customers were not relying on it.[154] As discussed below, there may be different considerations for customers of downstream pipelines that take assignments of capacity on upstream pipelines.

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153. Order No. 636-A at p. 30,600.

154. In response to Gas Consumers' comment, the Commission notes that a majority of pipelines currently offer small customer service using a one-part rate.

Appendix D

4. Upstream Pipelines

The APGA seeks clarification about the transportation rate to be paid by small customers which acquire upstream capacity under section 284.242 of the Commission's regulations. It maintains that the small customers charged a one-part rate by the downstream pipeline for transportion should also be charged a one-part rate by the upstream pipeline for upstream transportation. The APGA adds that the upstream pipeline must charge the one-part rate to one-part customers of downstream pipelines, even if the upstream pipeline has no direct customers that qualify for that rate.

TVMGA asks whether a pipeline that offered such a service on May 18, 1992, must offer the similar service to a small customer that was not receiving the small customer service on May 18, 1992. It maintains that this is important to small customers of downstream pipelines which will be taking service on upstream pipelines.

The Commission will not require upstream pipelines without a small customer service on May 18, 1992, to institute a small customer service to provide a small customer rate for transportation to small customers on downstream pipelines which, under section 284.242, are receiving an assignment of upstream transportation capacity held by the downstream pipeline. However, if an upstream pipeline had a small customer service on May 18, 1992, the issue of whether it should provide a one-part transportation rate to small customers receiving an assignment of upstream capacity should be considered in the restructuring proceeding. This will enable the parties to consider the small customers' need for such a service on the upstream pipeline and the impact of the additional small customers on

the rates charged to the upstream pipeline's current customers under the small customer schedule and its customers paying a two-part rate.

5. Eligibility Criteria

In Order No. 636-A, the Commission stated that eligibility criteria for the small customer rate service would be based on existing criteria.[155] CIG states that one such standard is that eligible entities must be LDCs or municipally-owned gas systems. It asks the Commission to clarify whether CIG can retain this standard and exclude non-LDCs and non-municipalities (*e.g.*, producers and marketers) in the new small customer transportation rate schedule. Consolidated Minerals, a direct customer of Florida Gas Transmission Company, argues that pipelines should be required to offer the small customer mitigation measure to all customers using small quantities of gas, whether or not they were jurisdictional customers. Interstate Power asks for clarification that the small customer rate be based only on service criteria in the rate schedule and not on the status of the customer, whether it is an LDC or a municipal utility.

As stated, the Commission's intent was not to modify eligibility criteria, except as needed to ensure that the pipeline recovers its costs. Hence, the Commission has made no change to the pipeline's service criteria, including its criteria with respect to the nature of the customer. A direct customer, therefore, would be eligible only if eligible under existing criteria, unless the parties to the restructuring proceeding otherwise agree.

In Order No. 636-A, the Commission required pipelines to

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155. This is other than the new criteria set forth in Order No. 636-A, relating to interruptible service and released capacity. *See infra.*

consider enlarging the size of the small customer class to include any customer with the right to transport up to 10,000 Mcf or Dth per day on a firm basis in order to mitigate the effect of shifting to SFV on small customers who do not currently qualify for a pipeline's small customer rate schedule. The Commission stated further that whether the small customer class should be so enlarged on a specific pipeline is an issue to be considered by the parties in the specific restructuring proceedings.

Atlanta Gas argues that the Commission has offered no justification for requiring pipelines to enlarge the size of the small customer class to include any customer with the right to ship up to 10,000 Mcf per day on a firm basis. It objects to the Commission's explanation that this will mitigate cost shifts caused by SFV as not reasoned.

Prior Energy argues that the Commission's definition of small customer, as one who ships no more than 10,000 Mcf or Dth of natural gas per day, will enable far too many shippers to qualify. It would permit only customers who at present qualify as small customers on each pipeline to keep that status.

Blue Flame also contends that the Commission erred in finding it appropriate to increase the size of the small customers class up to 10,000 Mcf or Dth per day. It asserts this will shift more costs to the usage charge and have an adverse impact on wellhead prices. It maintains that the use of seasonal reservation quantities will adequately treat undue cost shifts and that further mitigation for small customers is an undue preference.

Peoples Gas also opposes increasing the class of small customers as suggested by Order No. 636-A because it will simply increase their subsidy.

Appendix D

The Commission believes that the issue of whether a particular pipeline should increase the size of the small customer class up to 10,000 Mcf or Dth per day should be addressed in the restructuring proceedings. If necessary, the Commission will examine the issue on the merits, which will, among other things, enable the Commission to examine the extent of any cost shift to the non-small customers and to consider whether such an increase is so pervasive as to have an adverse impact on achieving the goals of the instant rule. In response to Blue Flame, the Commission observes that, unlike seasonal contract quantities, the one-part rate enables the small customers to match payments with receipt of service.

In Order No. 636-A, the Commission imposed two restrictions on eligibility for service at the small customer transportation rate. These were that the shipper cannot ship gas under any interruptible transportation service available from the pipeline and cannot ship gas as a replacement shipper under the capacity releasing mechanism of section 284.243 of the Commission's regulations unless the customer has exhausted its daily level of firm entitlement for that day.

Tenneco argues that additional restrictions are needed. It maintains that "no other shipper should be permitted to use the small customer's delivery point(s) as secondary points under a firm agreement, and small customers must be prohibited from receiving gas at their delivery points from an [interruptible transportation] shipper."[156] Tenneco claims that unless this loophole is closed "a small customer could circumvent the Commission's restrictions by simply buying gas from a third party shipper at its delivery point and receiving the difference

156. Petition at 9.

between the shipper's transportation and its own [firm transportation] rate through the price it would pay for the gas."[157]

The Commission's clarifies that its intent was that small customers receiving service at the small customer rate must first use the pipeline's firm transportation under the small customer rate schedule to provide the pipeline with the opportunity to recover its costs assigned to that service. Tenneco's argument comports with the Commission's interpretation of its regulations because it would prohibit evasion of the pipeline's firm transportation under the small customer service. A small customer should not be able to receive gas from third parties at the small customer's delivery points unless the small customer has exhausted its daily level of firm entitlement for that day in the aggregate.

Elizabethtown argues that the Commission should eliminate the condition that it (and others) cannot have access to interruptible transportation on Tennessee Gas Pipeline Company's (Tennessee) system at the same time it is using its small customer firm transportation service. Elizabethtown states that it must use interruptible transportation to avoid incurring penalties for exceeding its maximum annual quantity for firm service. Elizabethtown's argument is case-specific and should be raised in the Tennessee restructuring proceeding so that the Commission can determine, in acting on Tennessee's compliance filing, whether good cause exists to grant relief to Elizabethtown.

6. On-going Proceedings

Section 284.14(b)(3)(iv)(A) provides that a pipeline that must offer the small customer service must do so "on the same

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157. *Id.*

basis and under the same eligibility criteria as the small customer sales or transportation rate under the pipeline's last-approved tariff provisions for those services."

FMNGA states that on May 18, 1992, Florida Gas Transmission Company was billing its small customers on a two-part rate that is subject to refund and to the outcome of a hearing and a final Commission order yet to issue.[158] Florida Gas' proposed two-part rate was designed to recover the same revenue as the one-part rate contained in its last approved tariff. FMNGA asks the Commission to require Florida Gas to serve its small customers under either (1) the last-approved small customer rate or (2) a small customer rate that is at least as favorable as the rate treatment small customers were receiving as of May 18, 1992, even though the rate may not be a one-part rate based on an imputed load factor.

Atlanta Gas argues that the gas subsidy issue is being challenged on certain pipelines such as Southern Natural Gas Company and so the Commission has erred by deciding the merits of cases subject to on-the-record adjudications, without due process of law. It adds that deferring the resolution of the issue to a new rate proceeding is no answer.

The Commission has required Florida Gas to include as part of its compliance filing in Docket No. RS92-16-000 tariff sheets that offer firm transportation service on a one-part volumetric basis to customers presently serviced under Florida Gas' small customer rate schedule.[159] FMNGA should raise its

158. *See* Florida Gas Transmission Co., 56 FERC ¶ 61,180, *order on reh'g*, 57 FERC ¶ 61,171, *order denying reh'g*, 57 FERC ¶ 61,376 (1991).

159. Florida Gas Transmission Co., 61 FERC ¶ 61,019 (1992).

issues about Florida Gas' treatment of small customers in Florida Gas' restructuring proceeding.

The application of the generic determinations will be decided in the specific restructuring cases, with respect to the continuation of small customer rate schedules.

C. Miscellaneous Issues

1. Choice of Rates

The Municipal Gas Authority of Georgia asks whether small customers have the option to select one-part rate treatment or a two-part rate structure with seasonal billing determinants or some similar measure. It is concerned that on some pipelines it might be argued that seasonal billing determinants or some similar measure are not needed to comply with Order Nos. 636 and 636-A, if the pipeline simply offers a one-part firm transportation rate to small customers. It argues in support that it cannot compete for interruptible industrial load with interruptible transportation rates or with released capacity. In addition, it maintains it cannot accept two-part SFV rates without seasonal-type billing determinants. It describes this as a no-win situation, which provides no motivation for small customers to reduce any unnecessary contract entitlement or pursue industrial load. It asks the Commission to require the pipelines to provide a two-part rate structure with seasonal billing determinants for small, low load factor customers, whether or not such billing determinants are established for larger customers, as an option in lieu of one-part rates.

The Commission clarifies that the requirement that pipelines continue to offer service to their small customers at the one-part

rate, computed using an imputed load factor, and the requirement that they mitigate for significant cost shifts that may occur are independent. If a small customer wants to switch to a two-part rate, it may do so. The pipeline would then have to adopt measures to avoid a significant shift in revenue responsibility due to the switch to SFV, but not due to the loss of the imputed load factor.

2. Phasing-In Cost Shifts

In Order No. 636, as modified by Order No. 636-A, the Commission directed pipelines to phase-in cost shifts, if the use of SFV, *after* implementation of other ratemaking techniques designed to minimize significant cost shifts, still results in a 10 percent or greater increase in revenue responsibility for any historic customer class. This bright line mitigation measure is to phase-in any such rate increase over no more than a four-year period.

Southwest Gas seeks clarification about whether a class consists of all those customers under a particular rate schedule or those customers served under a particular rate schedule within the same rate zone. It refers to the order in *El Paso Natural Gas Co.*, as unclear.[160] There, the Commission stated that it "intended pipelines to perform mitigation measures by rate schedules within specific zones and not just by zones" as unclear.[161] In the alternative, it asks whether the definition of class is to be determined on a case-by-case basis.

Southwest Gas also asks for clarification that the mitigation

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160. 60 FERC ¶ 61,228 (1992).

161. *Id.* at p. 61,768.

for 10 percent or greater cost shift applies only to those customers within a class or classes that meet the bright line test.

The definition of class is to be determined on a case-by-case basis. However, contrary to Southwest, the mitigation measures required to be phased-in apply to the entire class, not to individual customers. Last, in response to the APGA's suggestion that this should be a permanent measure,[162] the Commission reaffirms that this mitigation measure is transitional and not permanent. This is because it relates to historic classes, some of which will no longer exist after unbundling is fully implemented.

3. Rates for Part 157 Transportation

In Order No. 636-A, the Commission stated that pipelines must charge the same rates for individually authorized NGA section 7(c) (Part 157) transportation and for Part 284 transportation and that it will permit individually authorized transportation rates to be so designed. However, the Commission stated that a party may raise any objection to that design in the restructuring proceeding.

Arkla objects to Part 157 shippers paying the same rates as Part 284 shippers for two reasons. First, it maintains that Part 157 transportation will, after restructuring, be inferior to Part 284 transportation (*e.g.*, the former is not permitted to participate in capacity releasing or have flexible receipt and delivery points). Second, it asserts that most individual transportation arrangements are economic only because of the negotiated

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162. The APGA also includes other mitigation measures in its argument that the rate for service to small customers should be permanent.

specific contract rates. It adds that Part 284 rates would unduly deprive the parties of the benefits of their bargains.

JMC Power Projects argues that the application of SFV rates to Part 157 shippers without capacity releasing is capricious.

The Commission clarifies that it intended only that rates for Part 157 transportation may be designed under SFV, with any appropriate mitigation.

The Commission did not mean that a pipeline had to charge the same reservation rate to both Part 157 transportation customers and Part 284 transportation customers. For example, an incremental reservation charge under Part 157 could be higher than a Part 284 reservation charge, even though both are designed under SFV. The application of SFV rates to Part 157 shippers is reasonable without capacity releasing because those shippers are entitled to mitigation to avoid significant shifts in revenue responsibility by customer and to the phasing-in of cost shifts of ten percent or greater for an historic customer class in connection with the application of SFV.

4. Contract Rates

Mojave asks for clarification about whether it must adopt SFV when it has contractually agreed to the use of a rate design inconsistent with SFV. It states that while its filed rates are designed under MFV, its contracts provide for rates that put both return on and of equity in the usage charge. The Indicated Shippers respond that this issue is *sui generis* to Mojave and should be addressed in its restructuring proceeding where they

plan to address it.[163] The Commission agrees with the Indicated Shippers that this issue (of the effect of SFV on existing contracts), should be resolved in individual restructuring proceedings so that the Commission can be informed fully about the facts and circumstances pertaining to those contracts and the positions of all parties.

The Producer Associations ask the Commission to clarify on rehearing that the "pipeline cannot use two-party negotiations to defeat the procompetitive policies represented by the Commission's adoption of an SFV rate design."[164] They are concerned about agreements between shippers and pipelines that specify MFV and about most favored nations clauses in some transportation agreements. The Commission reiterates that "it will carefully consider arguments for and against deviations from SFV, with the advocates against SFV bearing the burden of persuasion."[165] In addition, as further stated in Order No. 636-A, "[a]t a minimum, opponents of SFV must demonstrate that SFV is not needed to effectuate the goals of Order No. 636."[166]

5. Demand Charge Credits

In Order No. 636-A, the Commission concluded that the

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163. The Indicated Shippers' motion to file an answer out-of-time to Mojave's request for clarification and answer is granted.

164. Petition at 5.

165. Order No. 636-A at p. 30,605.

166. *Id.*

issue of whether pipelines should be required to provide demand charge credits during service interruption or curtailment, to provide an incentive to expeditiously restore service, should be resolved in individual rate proceedings because it does not pertain to Order No. 636.[167]

AGD argues that the imposition of an SFV rate design methodology justifies addressing this issue because it inseparably links firm service and demand charge payments. AGD also maintains that, by not allowing this issue to be considered in the restructuring proceedings, the Commission may have given pipelines unfair bargaining leverage. Last, it contends that the Commission has acted inconsistently with its prior treatment of this issue in *Northern Natural Gas Co.*, where it required the pipeline to give curtailed firm customers demand charge credits.[168] ConEd similarly argues that the Commission should address this issue in the restructuring proceedings because it is linked to SFV.

The Commission denies rehearing because it believes that this issue pertains to a demand charge designed under any rate design and is not so intimately related to SFV or any other provision of Order No. 636 as to require treatment in a restructuring proceeding.

6. Impact of Order No. 636 on Incremental Rates

In Order No. 636-A, the Commission stated the following about the impact of Order No. 636 on vintage pricing:

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167. *Id.* at p. 30,607.

168. 57 FERC ¶ 61,105 at p. 61,408 (1991).

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> Great Lakes Transmission Limited Partnership (Great Lakes) requests clarification that equal transportation on even terms requires the elimination of vintage pricing in favor of a uniform, market-based rate for comparable transportation services (constrained by the pipeline's highest cost-based tariff rate applicable to such services). The Commission will address this issue in Great Lakes' own proceedings concerned with vintage pricing rather than here or in the restructuring proceeding.[169]

Great Lakes and TransCanada ask whether the vintage issue is to be explored in Docket No. RP91-143, which is to deal with other issues with respect to implementing the incremental rates mandated for certain of Great Lakes' new services.[170]

The Fuel Managers Association asks the Commission to clarify that, during the restructuring proceedings, it will consider "whether a pipeline's use of incremental facilities would, as a result of restructuring, (a) justify rolled-in rate treatment for the incremental facilities or (b) require other mitigation measures in such matters as cost allocation or rate design to obtain fair and equitable treatment for incrementally-priced customers." [171]

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169. Order No. 636-A at p. 30,608.

170. Great Lakes Transmission Limited Partnership, Opinion No. 367, 57 FERC ¶ 61,140 and, Opinion No. 368, 57 FERC ¶ 61,141 (1991), reh'g pending of both opinions. The motions of Northern, Texas Eastern Transmission Corporation, and Natural to answer the requests for clarification by Great Lakes and TransCanada are granted.

171. Petition at 9. They describe as benefits the additional line pack (Cont'd)

The Commission agrees that issues with respect to the impact of the instant rule on so-called "vintage pricing" on Great Lakes should be addressed in Docket No. RP91-143. This issue is currently before the Commission and will be considered with the rehearing petitions of Opinion Nos. 367 and 368 and is not to be considered in Great Lakes' restructuring proceeding.[172] Further, to the extent the Commission has not previously acted on other rolled-in/incremental issues, they may be addressed in the restructuring proceedings.

7. Processing Rights

The Producer Associations argue that the Commission should adopt a generic policy applicable to all Part 284 pipelines engaging in gas processing and suggests the adoption of proposed language dealing with credits and other issues related to processing. The Commission will not use this rulemaking as a vehicle for adopting specific generic language with respect to gas processing since the rulemaking was not intended or designed to adopt generic rules or policies pertaining to gas processing except that the Commission, generally supports the principle that rates for processing should be unbundled from other services.[173] Further, the Commission has not received comment on the proposed language from other parties.

(Cont'd)
which may aid in the providing of no-notice service and the facilitation of releasing of aggregated capacity caused by increased pipeline capacity due to expansion.

172. Great Lakes Gas Transmission Limited Partnership, 57 FERC ¶ 61,140 and ¶ 61,141 (1991).

173. Order No. 636-A at p. 30, 609 ("[T]he Commission repeats its strong preference for fully unbundled services").

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VI. PIPELINE SALES

In Order No. 636, the Commission issued blanket sales certificates to open access pipelines authorizing firm and interruptible sales for resale at market-based rates. On rehearing of Order No. 636, the Commission modified Order No. 636 to require pipelines to continue to sell gas to their current small sales customers at a rate that is cost-based for a transitional one-year period.[174]

On rehearing, CNG asks the Commission to clarify that pipelines may impose take-or-pay obligations, minimum bills, one-part demand charges, or other reasonable terms to compensate the pipeline for acquiring the supplies needed to provide sales service to small customers. Further, CNG asks the Commission to condition small customer access to interruptible transportation and released capacity on the customer's satisfaction of its daily level of gas purchases from the pipeline. CNG asserts that small customers will have many options to secure supplies and that pipelines should not be compelled to secure supplies for one year without the small customers incurring some reciprocal obligation to purchase gas from the pipeline, or, at a minimum, compensate the pipeline for standing ready to serve. CNG notes that the Commission recognized the need for mutuality when it addressed small customers' transportation rates and conditioned small customers' access to released capacity and to interruptible transportation on a small customer's exhaustion of its daily levels of firm service entitlement for the day, and that the Commission should treat small customer sales similarly.

The Commission will not impose any minimum take

174. Order No. 636-A at p. 30,600.

requirements on the small customers and will not condition their access to released capacity or interruptible transportation on exhaustion of daily purchase requirements. The purpose of providing a transition period for small volume customers is to provide those customers with an opportunity to adjust to purchasing at negotiated prices and to gain experience in dealing with other suppliers. Requiring the small customer to meet minimum purchase requirements would defeat the purpose of this provision.

The transitional sales rate should not impose a significant burden on the pipelines. The provision is temporary and will be in effect for only a brief, one-year period. Moreover, by definition, the customers purchasing under this rate will be taking small volumes and the supply impact on the pipeline should be negligible. If a pipeline believes that the supply impact on its system will be substantial, it may address this issue in its restructuring proceeding.

For these same reasons, the Commission will not authorize the pipelines to reinstitute a minimum bill for small customers for the transition period. The pipelines have no minimum bill today and the transition period merely maintains the status quo for small customers.

The pipelines will be able to recover the gas costs associated with providing this service, but may not do so through minimum take or minimum bill requirements. The pipelines should address in the restructuring proceedings other proposals for cost recovery.

PGT asks the Commission to clarify that Order No. 636-A does not preclude cost-based sales rates for other customers as

well as small customers. PGT notes that in the NOPR, the Commission specifically indicated that pipelines could chose between cost-based or market-based rates,[175] but that Order No. 636 does not specifically address this issue. PGT also refers to the statement in Order No. 636-A that the Commission expects that pipelines will terminate their PGA mechanisms and initiate market based pricing of gas in order to remain competitive in the sales market,[176] but that pipelines are not prohibited from negotiating cost-tracking systems with their customers.[177]

The Commission clarifies that the blanket certificates authorize the pipelines to negotiate sales rates with their customers, and nothing in the rule prohibits the pipelines and customers from agreeing to rates that are based strictly on costs or, for that matter, any other basis. However, the Commission will not establish specific cost-based rates for gas sales for the parties and will not design a specific mechanism for gas cost recovery. This is a matter for negotiation between the parties. Because the Commission has decided to allow the parties to negotiate gas sales prices, the Commission will not engage in the same kind of regulatory oversight and review that it has used with the PGA mechanisms for the review of gas sales prices. The Commission intends to concentrate its regulatory focus on the transportation aspects of the pipeline's business. However, as the Commission explained in Order No. 636,[178] the parties to the restructuring proceedings may seek to prove that adequate

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175. IV FERC Stats & Regs ¶ 32,480 at pp. 32,559 - 32,560 (1991).

176. Order No. 636-A at p. 30,651.

177. *Id.* at 30,651 n.473.

178. Order No. 636 at p. 30,441.

divertible supplies of gas do not exist with respect to a particular pipeline and, if the parties sustain the burden of proof on this issue, the Commission will engage in more active regulation of that pipeline's sales.

VII. PIPELINE SERVICE OBLIGATION (AFTER RESTRUCTURING)

In Order No. 636-A, the Commission modified Order No. 636 to provide that in exercising the right of first refusal to retain capacity, the long-term firm transportation customer must match the price offered by a competing bidder, up to the maximum just and reasonable rate, and the longest contract term, up to a maximum period of 20 years. The requests for rehearing[179] object to the Commission's determination that capping the bidding at 20 years is an appropriate balance of the pipeline's need for stability and the customer's need for flexibility. In addition, UDC and UGI Utilities argue that the Commission should exempt from pregranted abandonment all firm shippers with contractual waivers of pre-granted abandonment. LILCO and APGA ask the Commission to require pipelines to accept the highest bid for capacity, even if the bid is below the maximum rate.

A. Length of Contract Term

The parties argue that the 20-year cap on the bidding adopted by the Commission does not reflect the comments of the parties, does not remedy their concerns, does not address

179. Requests for rehearing on this portion of the rule were filed by AGA, AGD, ConEd, Interstate Power, Utilicorp Divisions, Northern States, Peoples Gas, PSE&G, UGI, UDC, Washington Gas, State Commissions, NJBRC, Industrial Groups and Consolidated Minerals.

pertinent facts raised by the parties, is not supported by record evidence, and, therefore, is arbitrary, capricious, and not reasoned decisionmaking. These parties note that the majority of commenters asked for a cap on the bidding at a term of five years, others asked for a cap of three to ten years, but no one suggested the 20-year cap adopted by the Commission. In addition, they assert that the Commission has not addressed their concern that LDCs cannot accurately forecast their needs so far into the future nor answered their argument that this bidding requirement will in fact limit competition, contrary to the goals of the rule, by denying LDCs the flexibility to respond to changing market conditions.[180]

Further, the parties state the Commission has failed to respond to the contention that this bidding requirement tips the balance in favor of unregulated producers and marketers and will encourage speculation in pipeline capacity. Consolidated Minerals argues that under the rule, large shippers will reserve space on constrained pipelines to repackage it, and thus will determine who will have access to the pipeline.

In addition, State Commissions argue that the Commission failed to explain why long-term needs should have priority over short-term needs, and Interstate Power argues that the Commission failed to address its concern that these long-term contracts will not withstand state prudence reviews. People's Gas and UGI argue that this provision, coupled with the SFV rate design, will give pipelines no incentive to maintain or improve service.

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180. State Commissions note that the Department of Energy has recently sought comments on the effect of long term contracts on competition for natural gas. Notice of Inquiry, 57 Fed. Reg. 38182 (August 21, 1992).

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AGD and Interstate Power assert that there is no record evidence to support the Commission's rationale that 20 years has been the traditional length of service contracts in the industry. Further, several parties assert that the examples given by the Commission of such long-term contracts [181] are not representative of industry practice because these contracts support construction, and new projects generally require long-term agreements to support financing arrangements.

The Commission denies rehearing on this issue. The parties have misunderstood the purpose of the bidding cap and how the Commission expects the cap to function. Various parties have suggested that the Commission cap the bidding at one to ten years because they believe that to be an appropriate contract length for them in the current environment. The Commission, however, will not select the contract term for the parties. The purpose of the rule is to permit the market to determine contract terms, including duration. Therefore, the Commission capped the bidding at what it believes to be a reasonable outer boundary which still permits flexibility. The Commission is not requiring 20-year contracts and does not expect 20-year contracts to become the norm. Rather, the Commission capped the bidding at the outer, reasonable edge in order to give the market maximum flexibility to work within reasonable bounds. A firm shipper will have to commit to a 20-year contract only if a competing bidder values the service sufficiently to bid the maximum period.

Indeed, it is inconsistent that some petitioners argue that

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181. The Commission cited Pacific Gas Transmission, 56 FERC ¶ 61,192 (1991) and Iroquois Gas Transmission System, 53 FERC ¶ 61,194 (1990), *reh'g granted in part and denied in part*, 54 FERC ¶ 61,103 (1991) as examples of 20-year contracts. Order No. 636-A at p. 30,631 n.437.

the 20-year contract cap is too long while at the same time they express concern about security of supply in obtaining long term capacity. There is, of course, always a risk and an element of uncertainty in any forecast of future needs. LDCs are not unique among gas users in this regard. The Commission does not believe that LDCs are at a disadvantage with respect to other gas users in predicting future needs when exercising the right of first refusal. It is the Commission's judgement, based on industry practice, and in view of the types of contracts cited in Order No. 636-A,[182] that 20 years is a reasonable accommodation between the interests of stability and flexibility and provides a workable framework for market determinations. It is the Commission's judgement as well that the 20-year cap is a reasonable balance between ensuring that capacity is allocated to shippers that most value it and the LDC's need to maintain security of supply through capacity entitlements. However, if all the parties to a pipeline's restructuring proceeding agree to a different number of years for the contract cap, then the Commission will allow it.

UtiliCorp Divisions argue that the Commission does not give adequate weight to the presumption in favor of continued service or to the danger that the pipelines will use monopoly power to extract non-price concessions from the LDCs. Therefore, it concludes, the Commission has failed to adequately address the basis of the remand in *AGA II*, that the Commission has not explained how pregranted abandonment trumps another precept of regulation, *i.e.*, the protection of consumers against monopoly power through the refusal of service at the end of the contract period. Industrial Groups argue that there may be instances where continued service for a short term is in the

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182. Order No. 636-A at 30,631 n.437.

public interest, but the procedure adopted here does not afford parties the opportunity to explain the relevant circumstances.

As the Commission has explained, the right of first refusal procedure affords protection to the existing customer against any exercise of monopoly power.[183] The existing customer can always continue to receive service if it matches a competing bid. If there is no competing bid, the existing customer can always continue to receive service for any period it chooses by agreeing to pay the maximum rate. It is not contrary to the public interest to require customers to match the longest term bid to continue to receive service — especially where there is a reasonable cap on what constitutes the longest term bid. As the Commission explained in Order No. 636-A, long-term contracts generally benefit the system as a whole because they provide stability and benefits to all customers,[184] and section 7 of the NGA does not require the Commission to examine the particular circumstances of each case.[185] The right of first refusal procedure guarantees that existing customers may have continued service, while allowing market forces to play a significant role in determining the contract price and term.

B. Contractual Waiver of Pregranted Abandonment

In Order No. 636, the Commission stated that the pregranted abandonment provisions would not apply to conversions that

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183. Order No. 636-A at p. 30,631.

184. Order No. 636-A at p. 30,630.

185. Mobile Exploration and Production Southeast, Inc. v. United Distribution Companies, 111 S. Ct. 615 (1991).

took place during the period that the stay of pregranted abandonment under Order No. 500-J was in effect.[186] In Order No. 636-A, the Commission clarified that it would not expand the exemption from the pregranted abandonment provisions beyond those conversions that took place during the time the Order No. 500-J stay was in effect and stated that specific contracts that contain a waiver of the right to pregranted abandonment should be examined in the restructuring proceedings and not in this generic proceeding.

On rehearing, AGD and UDC argue that the Commission erred in deferring the examination of specific contractual waivers of pregranted abandonment to the restructuring proceedings. These parties argue that they won this protection through difficult negotiations and should not be required to fight this battle again during restructuring. UGI argues that the voluntary waiver of pregranted abandonment completely eliminates the legal and theoretical basis for requiring that capacity subject to these contracts go through the right of first refusal process in order to avoid pregranted abandonment. The parties ask the Commission to affirm, generically, that existing rights to waiver of pregranted abandonment will remain unmodified.

As the Commission explained in Order No. 636-A, the exemption from pregranted abandonment for conversions that took place during the Order No. 500-J stay is based on the Commission's decision in that proceeding and the resulting expectations of the parties.[187] It is appropriate, therefore, to clarify in this proceeding that those conversions will not be

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186. Order No. 636 at p. 30,452.

187. Order No. 636-A at 30,636.

subject to pregranted abandonment. Further, as a general matter, the parties may resolve issues in Commission proceedings by contractual agreements or settlements, and the Commission generally favors the resolution of issues by settlement. However, the Commission will not rule on the viability of any current settlements or contractual agreements in whole or in part, on a generic basis. The relationship between the provisions of existing settlements or agreements and the provisions of this rule will have to be examined on a case-by-case basis. This rule is not intended to affect existing valid waivers of pregranted abandonment, but the Commission will not rule on any specific waiver provisions here.

C. Bids Below the Maximum Rate

In Order No. 636-A, the Commission clarified that pipelines are not required to discount transportation rates under the rule and that if a lower bid is not acceptable to the pipeline, then the shipper is entitled to continued service at a rate between the minimum and the maximum negotiated by the shipper and the pipeline.[188] LILCO, APGA, and Meridian ask the Commission to require pipelines to accept the highest bid for capacity made available as the result of the bidding process at the termination of the contract. LILCO states that if pipelines are not required to accept offers at less than the maximum rate, then they will be able to refuse offers for discounted service and seek recovery of the costs associated with the unwanted capacity from their remaining customers through a section 4 filing. To prevent unnecessary cost shifts, LILCO argues, the Commission should grant rehearing and require pipelines to accept bids at less than the maximum rate where there are no other offers for capacity,

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188. Order No. 636-A at p. 30,629.

or forbid pipelines from recovering the cost of unwanted capacity from other shippers.

APGA and Meridian argue that unless pipelines are required to accept the highest bid, the market will not, in fact, determine the rate. APGA asserts that captive LDCs will have little leverage to negotiate if pipelines can reject a rate below the maximum. Meridian asserts that while the procedure set forth in Order No. 636-A may work on capacity-constrained pipelines, it will not work on pipelines where capacity is not fully utilized. Moreover, Meridian argues, since the bid that is received reflects the market value of the capacity, that is the rate and term that should be matched by the existing shipper. Meridian asks the Commission to clarify that where a pipeline refuses to accept a bid below the maximum rate, the pipeline, and not the customers, is at risk for any shortfall.

The Commission will not require pipelines to discount transportation rates. However, if a pipeline fails to attempt to maximize throughput, there is no guarantee that it will be able to recover all the cost of its underutilized capacity from its firm customers when it files its next rate case.[189] Evidence that a pipeline refused to accept the highest valued bid for capacity below the maximum rate will be given significant weight during its next rate case.

Meridian believes that the rule does not require the pipeline to reveal that a below maximum bid, or no bid at all, was offered for the capacity and asks the Commission to clarify that pipelines must post the highest bid actually received (or the fact that no

189. *See* Order No. 436, Regulation of Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Stats. Regulations Preambles 1982-1985 ¶ 30,665 at p. 31,523.

bid was received). The rule does not explicitly require pipelines to post competing bids on the bulletin board. However, it was the Commission's intent that the existing shipper have notice of the terms of all competing bids. The Commission clarifies that the pipeline must inform the existing shipper of the maximum bid received or the fact that no bids were received on the EBB. Moreover, the pipelines are required to publish in their tariffs the criteria they will use to determine the "best bid."

Meridian also asks the Commission to clarify that the previously effective rate should remain in effect during the period the pipeline and the customers are negotiating the terms for continued service. The Commission will grant the clarification.

VIII. TRANSITION AND IMPLEMENTATION IN THE RESTRUCTURING PROCEEDINGS

A. Capacity Adjustments During Restructuring

Under section 284.14(e) of the Commission's regulations, firm shippers (including currently bundled sales customers) must give notice to the pipeline during the restructuring proceeding whether they wish to retain, reduce, or terminate their contractual rights to firm transportation service. The pipeline is authorized to abandon firm transportation service to the existing shipper if another creditworthy shipper offers to pay for the capacity an existing shipper wants to release, or offers to pay a higher rate (up to the maximum rate) than the existing shipper is willing to match, or the pipeline consents to the abandonment even though no other shipper makes an offer for it. Several parties reiterate concerns with issues already addressed in Order No. 636-A or request clarification of certain issues. The Commission will deny

the requests for rehearing but clarify certain issues as discussed below.

1. Unilateral Right to Reduce or Terminate CD

Meridian asks that existing capacity holders be given a unilateral right to reduce or terminate their contract demand (CD) during the restructuring proceedings. Meridian argues that, facing the prospect of an SFV rate design, shippers should be given the choice to reduce their contract demands or terminate their service agreements, thereby returning capacity to the pool and making it available for assignment to others willing to assume the costs and risks associated with SFV-based rates. Meridian asserts that, under section 284.14(e)(2) of the regulations, a firm customer paying the maximum rate is effectively trapped on pipelines where there is insufficient demand for capacity to be relinquished. Meridian recognizes that the pipeline might have to increase the demand charges of the customers with continued interest in firm service in order to afford relief to those who reduce or terminate their capacity reservations.

Cincinnati Gas contends that Order No. 636-A should be revised to impose an obligation on pipelines, in cases where there are no bidders for particular capacity during the restructuring process, to enter into good faith negotiations with the current capacity holder for the purpose of agreeing to a rate reflective of the capacity's actual worth. If such negotiations do not result in an agreement on an acceptable rate, Cincinnati Gas argues that shippers should be allowed to release the capacity, and that any costs associated with such releases should be treated as stranded costs.

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The Commission has already considered and rejected proposals like Meridian's and Cincinnati Gas' in Order No. 636-A.[190] In order to afford unilateral relief to firm customers that want to reduce or terminate their capacity reservations, or reduce their rates for capacity during restructuring, before their contractual obligations for the capacity have expired, the costs allocated to rates for the capacity in question would have to be absorbed by the pipeline or reallocated to other firm customers who may have no current need for the capacity. The parties are, of course, free to negotiate capacity allocation matters during the restructuring proceedings.

2. Expiration of Bundled Sales Contracts During Restructuring

UtiliCorp Divisions asks a question arising from the restructuring proceeding of Williams Natural Gas Company, where it indicates that certain sales customers have executed contracts that expire when superseded by another contract, or November 1, 1993, at the latest. UtiliCorp Divisions ask whether a current firm capacity holder with a contract that terminates on or prior to the date of restructuring, *i.e.*, the effective date of the pipeline's tariffs to comply with Order No. 636, may retain capacity following restructuring by agreeing to pay the pipeline's maximum rates and freely select the term for the first post-restructuring contract, or must also match the duration of a contract bid by potential new customers for that capacity. UtiliCorp Divisions argue that historic customers should be permitted to elect any term for their first post-restructuring contract as long as they are willing to pay the maximum rate. It reads Order No. 636-A to permit that result,

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190. Order No. 636-A at p. 30,637-39.

and to defer the application of the right of first refusal procedures until after the term of the first contract. UtiliCorp Division also ask a subsidiary question: If the existing capacity holders whose sales contracts expire on or before November 1, 1993, have to match the length of terms offered by competing bidders, do they have to offer to enter into contracts for a term of 15 years, as Williams requires, or may they simply agree to match the length of term offered by competing bidders?

The Commission will not address the specific facts and circumstances in the Williams restructuring proceeding in this generic order. However, UtiliCorp Divisions' rehearing request indicates a general area of confusion which needs clarification.

Questions have arisen about the applicable policies when long-term bundled sales contracts expire after the effective date of Order No. 636, but before the effective date of a pipeline's blanket sales certificate under section 284.284, when the pipeline's bundled sales service is converted to unbundled sales and transportation services. The pipeline must continue to provide service under the service obligation of its existing certificate until its section 284.284 blanket certificate becomes effective. The pipeline and the sales customer may enter into a relatively short-term contract, intended to apply until the effective date of the pipeline's blanket sales certificate under section 284.284. If the pipeline and the sales customer enter into a contract for bundled sales service that extends beyond the date that the pipeline implements unbundled service, the contract will be converted into an unbundled sales and unbundled transportation contract on the effective date of the pipeline's 284.284 blanket certificate. The question arises whether the sales customer whose contract lapses during the restructuring process, and which is not renewed, has a right of

first refusal to retain its firm transportation capacity upon the effective date of the pipeline's section 284.284 certificate, and whether a customer with a short-term interim sales contract has a right of first refusal to retain its capacity upon expiration of its short-term contract on or after the effective date of the pipeline's section 284.284 certificate.

In *ANR Pipeline Company*,[191] the Commission decided to treat short-term (less than one year) interim, bundled sales contracts as long-term contracts for purposes of affording the bundled sales customers the right of first refusal to avoid automatic abandonment of their firm transportation capacity — even if the contracts in fact expire in less than one year. The Commission will apply the same treatment given to short-term contracts in *ANR* to other pipelines undergoing restructuring whose long-term sales contracts expire during the restructuring process. A customer whose long-term bundled sales contract (one year or more) expires after May 18, 1992, but before the effective date of a pipeline's section 284.284 certificate, is entitled to retain its firm capacity by exercising a right of first refusal, as described in section 284.221(d) of the Commission's regulations, in connection with implementation of the pipeline's section 284.284 certificate. The customer is entitled to exercise its right of first refusal to avoid abandonment of service whether or not it executes an interim contract, or upon expiration of any interim contract, whether the interim contract is for more or less than one year.

In exercising this right of first refusal in connection with implementation of the pipeline's section 284.284 certificate, a customer is entitled to retain its firm capacity by matching the

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191. 60 FERC ¶ 61,319 (1992).

price offered by a competing bidder, up to the maximum rate,[192] and the duration of the term bid, up to a maximum of 20 years. The pipeline may not require a customer exercising its right of first refusal to contract for some term of longer duration than a term offered by a competing bidder. And, as the Commission said in Order No. 636, if there are no competing bidders, the existing customer is entitled to continue service for whatever term it chooses.[193]

3. Liability of Existing Shipper for Reallocated Capacity

Barclays seeks clarification that if capacity is reallocated during restructuring, and a new shipper's contract is for a shorter term than the existing shipper's term, the existing shipper will remain liable for the remainder of the term of the original contract. Barclays argues that if a holder of long-term firm capacity seeks to relinquish that capacity to another bidder during the restructuring proceeding, the pipeline, in addition to applying its creditworthiness standards, should remain protected not only from a shortfall in price but also from a shortfall in contract duration.

The Commission will grant this clarification. In Order No. 636-A, the Commission stated that when another creditworthy

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192. The pipeline may choose not to accept any bid at less than the maximum, in which event the existing customer will have to pay the maximum rate to retain its capacity. See Order No. 636-A at p. 30,629. However, as discussed above, if the pipeline refuses to accept a bid at less than the maximum rate, and the capacity goes unsubscribed, then this will be given significant weight in the pipeline's next rate case.

193. Order No. 636 at p. 30,449.

shipper offers to pay a rate that is equal to or greater than the existing capacity holder's rate for a *part* of the capacity the existing holder seeks to relinquish, a pipeline would be required to release the existing capacity holder from its contractual obligation for the part sought by the other shipper.[194] By extension, an existing capacity holder remains liable under the original contract for any part of a term remaining under the original contract when the contract of the shipper to whom capacity is relinquished expires.

4. Discounted Transportation Rates

CIG argues that the Commission erred in permitting an existing shipper with a contractually guaranteed transportation discount to retain the capacity in the restructuring proceeding by matching bids only up to the contractual rate, rather than the maximum rate. According to CIG, this policy undermines the allocative efficiency of capacity reallocation during restructuring. At the very least, CIG contends, an existing shipper with a discount that will not match higher bids for the capacity should not be entitled to the service enhancements provided for firm service under Order No. 636.

The allocative efficiency of capacity reallocation during restructuring is subordinate to the contractual rights of existing capacity holders. If a shipper contracted for long-term transportation capacity at a guaranteed discount, and has a contract that establishes its contractual right to receive that discount, the shipper is entitled to the benefits of its bargain under the contract, even if unforeseen circumstances render that service more valuable than it was when the bargain was made.

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194. Order No. 636-A at p. 30,639.

This result is merely the obverse of the continuing liability of a shipper that agreed to pay the maximum rate under its contract, even though unforeseen circumstances result in the shipper's rates unexpectedly increasing, or the shipper's need for the service unexpectedly decreasing.

5. Direct Feed Situations

UGI describes a contract for purchase of gas from Columbia under which delivery is made to UGI from Texas Eastern, a pipeline upstream of Columbia, a situation UGI characterizes as a "direct feed." UGI requests the Commission to clarify that if Columbia assigns its capacity on Texas Eastern to UGI, UGI will be entitled to a reduction in firm entitlements from Columbia, without exit fees or transition cost allocation, following the assignment of "direct feed" upstream capacity. Otherwise, UGI asserts that it will be liable for demand charges and transition cost charges to both Texas Eastern and Columbia for the same firm capacity.

The Commission will not attempt to resolve this case-specific issue arising from what appears to be an anomalous situation in this generic proceeding. The issue should be presented in Columbia's restructuring proceeding.

B. Transition Costs

1. Allocation of Gas Supply Realignment Costs to Interruptible Transportation

In Order 636-A, the Commission required pipelines to recover 10 percent of their gas supply realignment (GSR) costs through their rates for interruptible transportation (IT) under

their Part 284 blanket certificates. Many of the requests for rehearing of Order No. 636-A take issue with this requirement. Various parties oppose the allocation of GSR costs to interruptible transportation customers and propose that such costs be recovered from firm transportation (FT) released under the pipeline's capacity release program, or released firm transportation subject to a right of recall, as well as interruptible transportation. Some parties advocate that the 10 percent of GSR costs allocable to interruptible transportation should be recoverable from firm transportation if the pipeline does not provide interruptible transportation service, or if the volumes of interruptible transportation service it provides are insufficient to bear the 10 percent allocation. Other parties propose that a higher percentage of GSR costs should be recoverable from interruptible transportation service, or that all GSR costs should be recoverable through a volumetric surcharge on all throughput.

a. Arguments against the allocation to IT

The American Paper Institute asserts that GSR costs should not be allocated to interruptible transportation customers, or at least, not to the extent that interruptible transportation customers pay higher GSR costs per unit than firm transportation customers. GSR costs should not be allocated to Part 284 interruptible transportation customers, the Paper Institute argues, because interruptible transportation customers will not benefit from Order No. 636, they have not and will not cause GSR costs, and achieving the transition required by Order No. 636 through subsidization by interruptible customers is not in the public interest. It is not appropriate, according to the Paper Institute, to view opportunities for interruptible transportation customers to obtain firm service through the capacity release program as a basis for charging GSR costs to interruptible

transportation customers. Furthermore, the unbundling requirements of Order No. 636 do not benefit interruptible transportation customers, and pipelines in many restructuring proceedings are attempting to reduce the scheduling and balancing flexibility available to traditional transportation services, including interruptible transportation service.

The Paper Institute also notes that if the amount of interruptible transportation throughput is sufficiently low, it is conceivable that interruptible transportation customers could pay more, on a per unit basis, than do firm customers, and advocates that the Commission should at least adopt a mechanism which avoids that result.

Industrial Groups argue that the Commission's decision to allocate 10 percent of the GSR costs to interruptible transportation services is arbitrary and capricious, and that the rate impact of spreading GSR costs to a shrinking class of interruptible transportation customers is significant, and far out of proportion to any imaginable benefit to interruptible transportation shippers from the restructuring rule.[195] Industrial Groups argue that the Commission erred in Order No. 636-A by allocating GSR costs to interruptible transportation and non-converting firm transportation customers without a showing that interruptible transportation and non-converting firm shippers have contributed in any way to the incurrence of such costs, or that the ordered level of allocation produces just and reasonable

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195. They argue that the Texas Eastern filing of nearly $.28 per dekatherm for the GSR charges on interruptible transportation, which more than doubles the cost of various production and market area hauls, illustrates that the Commission cannot arbitrarily assign a predetermined percentage of costs to interruptible transportation.

rates. They also assert that sales contracts, and any costs that might be incurred to modify them, are unrelated to any service provided by pipelines for transportation customers who have never been pipeline sales customers, or who converted to transportation before the issuance of Order No. 636.[196]

Industrial Groups assert that interruptible transportation customers are provided no additional rights or services under the restructuring rule, and that because GSR costs are sales-related, they are not affected by the amount of interruptible transportation service a pipeline provides. They argue that the initiatives adopted in Order No. 636, such as unbundling, flexible receipt and delivery points, and creation of a uniform national capacity release program, will enhance the ability of firm shippers to use their reserved capacity more efficiently, but diminish the quality and reliability of interruptible transportation service by reducing the amount of pipeline capacity available for interruptible transportation service. In fact, they argue, these measures may lead to complete displacement of interruptible transportation service. Industrial Groups also argue that the Commission's cost-spreading rationale is inconsistent with its decision to exempt NGA section 7 shippers

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196. Gas Consumers also argue that customers who pursued the Commission's policies under Order No. 436 and converted to transportation-only will not benefit from Order Nos. 636 and 636-A, and should therefore not bear the transition costs of restructuring, because they have already paid the transition costs of converting to transportation under Order No. 436. The rationale for allocating transition costs to firm transportation customers receiving service under Part 284 certificates, regardless of whether they are discontinuing purchases of gas from the pipeline, has been fully explained in Order No. 636-A, and will not be repeated in this order. *See* Order No. 636-A at p. 30,650.

and pipelines themselves from sharing transition costs.[197]

In the Commission's judgment, applying the principle of cost causation is more important when allocating costs and designing rates for the long term, and deviations from that principle may be justified for short term rates. The issue the Commission faces in this proceeding is how to provide for an equitable means of allowing recovery of the costs of the transition to a restructured pipeline industry and a more competitive natural gas market. The Commission recognizes that interruptible transportation service *as such* did not give rise to the GSR costs at issue here. Furthermore, interruptible transportation *as such* may not be enhanced or improved by the requirements of restructuring. However, customers that have historically used interruptible transportation, and may continue to use it on a restructured pipeline, have access to the enhanced firm services. More importantly, they will benefit significantly from access to the more competitive gas market that will be available as a result of restructuring. The Commission intends to spread the costs of transition over a broad base of customers that have access to these benefits.[198] Shippers on a restructured pipeline should not be able to completely avoid a fair share of the GSR transition costs by limiting their usage of the services available under the pipeline's Part 284 blanket certificate to interruptible transportation service.

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197. Arcadian also contends that there is no justification for treating IT shippers differently than section 7(c) shippers.

198. For the same reason, the Commission will deny LILCO's request that future open-access, transportation customers, that obtain service after restructuring is completed, should not be subject to transition costs.

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Producer Associations contend that the Commission erred by requiring that 10 percent of the GSR costs must be recovered through a usage surcharge on interruptible transportation because of the adverse effect of such charges on the net-back price of gas at the wellhead. Blue Flame also alleges that recovery of 10 percent of the GSR costs from interruptible transportation penalizes small and medium sized producers because of the net-back effect on spot prices.

Arkla states that the Commission apparently recognized cost causation principles in deciding not to allocate GSR costs to individually certificated section 7(c) transportation agreements, but failed to consider these principles in allocating GSR costs to Part 284 interruptible transportation customers.

The Commission recognizes that allocation of a small portion of a pipeline's GSR costs to interruptible transportation service may have some adverse impact on producer prices, at least for some transactions for a short term, but the public interest in a more equitable spreading of such costs to a broad base of pipelines' customers outweighs the possible short-term impacts on producers. The restructuring requirements of Order No. 636 are applicable to service under a pipeline's Part 284 blanket certificate. They do not pertain to transportation service under individual section 7(c) certificates. Part 157 shippers therefore do not get either the benefits or the burdens of Order No. 636.

b. Recovery of GSR costs not recoverable from IT

Several petitioners contend that the Commission should permit alternative mechanisms for recovery of the 10 percent of

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GSR costs allocated to interruptible transportation, such as applying an equivalent surcharge to released firm capacity, either capacity subject to recall or all released capacity.[199] These petitioners assert that, with the implementation of capacity release, they will be unable to recover the GSR costs assigned to interruptible transportation, because competition from released capacity will significantly reduce interruptible throughput, and the imposition of a surcharge on interruptible transportation will further reduce interruptible sales by making the rates for interruptible service uncompetitive with the rates for released capacity. They maintain that released capacity is the equivalent of interruptible capacity and should therefore bear the same responsibility for GSR costs.

The Commission does not agree that the implementation of capacity release programs will necessarily result in the elimination of interruptible transportation service or in the pipeline's inability to recover GSR costs assigned to such service. Nor will the allocation of GSR costs necessarily make interruptible transportation uncompetitive with released firm capacity or reduce interruptible throughput. If the market for interruptible transportation is competitive, as petitioners assume, pipelines will price to reflect competitive forces in the market, not costs. By pricing interruptible transportation competitively, the pipelines should be able to continue to sell the service. The Commission is not requiring pipelines to allocate such a high level of GSR costs to interruptible transportation service so that rates which recover such costs will render the service unmarketable.

Natural requests clarification that the Commission will allow

199. ANR (recallable releases); CIG (recallable releases); Southern (all releases); Tenneco (all releases).

the pipelines to develop mechanisms to adequately deal with any underrecovery of costs allocated to interruptible transportation. Natural asserts that the allocation of transition costs to interruptible transportation service will undermine the Commission's principle of 100 percent recovery of transition costs unless the Commission clarifies that pipelines are to be afforded flexibility to develop adequate mechanisms to deal with any underrecovery. According to Natural, higher rates for interruptible transportation service will render increasingly difficult the collection of any of the costs required by Order No. 636-A to be allocated to such service. Natural urges the Commission to permit a wide range of alternative mechanisms for recovery of the GSR costs allocated to interruptible transportation under Order No. 636-A, including

* allocation of zero non-gas fixed costs to interruptible services, with actual dollars collected by the pipeline for these services used first to collect the transition costs;

* direct billing (and/or reallocation to the demand surcharge or other cost recovery mechanism) of any underrecovered amounts after a predetermined time period;

* recovery in a later period (and/or under a different mechanism) of costs not recovered earlier due to seasonal or market factors.

K N asserts that because interruptible transportation is not available on all pipelines, and, where it is available, actual throughput may be significantly less than projected throughput used to design rates, the requirement that GSR costs be recovered from interruptible transportation customers may mean that

certain pipelines will not recover 100 percent of their gas supply realignment costs, absent an unconditional true-up mechanism applicable to all *firm* Part 284 transportation customers, which provides for recovery of carrying charges. LILCO, on the other hand, seeks clarification that a true-up mechanism for recovery of GSR costs allocated to interruptible transportation service may *not* provide for recovery from firm transportation service, but only from future interruptible service.

POPCO and PIOC allege that the Commission cannot require 10 percent of their GSR costs to be recovered from interruptible transportation service because they have never provided, and never expect to provide, interruptible transportation service. According to POPCO and PIOC, they were both certificated as gas supply projects, not transportation networks, and both are "open access" transporters pursuant to Order No. 509, but neither have ever received a request for firm or interruptible transportation of a presently deliverable gas supply. POPCO states that if the Commission applies its "90-10" rule to POPCO and PIOC, both pipelines will be denied an opportunity to recover the 10 percent of GSR costs allocated to interruptible transportation service.

The effect of capacity releasing on the levels and rates for interruptible transportation, and the ability to recover the assigned GSR costs, will depend on many factors, including the extent of projected GSR costs, characteristics of the pipeline's system, the pipeline's capacity release procedures, the extent to which flexible receipt and delivery points are available, the rate design used for interruptible transportation, and the use of seasonal contract entitlements.[200] As the Commission stated in

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200. For example, as the Commission pointed out in Order No. 636-
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Order No. 636-A, the Commission does not intend for the pipelines to have to absorb the portion of GSR costs assigned to interruptible transportation and encourages the pipelines and the parties to the restructuring proceedings to be creative in fashioning rate mechanisms, such as an appropriate true-up mechanism, that provide a reasonable opportunity for pipelines to recover those costs.[201] Furthermore, if a pipeline's experience after restructuring indicates that it will be unable to recover the 10 percent of GSR costs allocable to interruptible transportation, either because it is providing no interruptible transportation, or a *de minimis* level of such transportation, the Commission will consider proposals in limited section 4 rate filings to provide for recovery of those unrecoverablecosts.[202] However, the Commission will not accept proposals to assess any of the 10 percent of GSR costs allocable to interruptible transportation solely to *released* firm capacity. Released firm capacity already bears the cost of the reservation fee surcharge. Thus, permitting pipelines to assess the use of released firm capacity with an additional increment of GSR costs, while the pipeline's

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A, under a potential revenue crediting approach for interruptible transportation, pipelines could retain a portion of the revenue from interruptible transportation to recover GSR costs allocated to interruptible transportation. Order No. 636-A at p. 30,563 n. 164. The use of seasonal contract entitlements likely would result in interruptible transportation being available in the off-peak season.

201. Order No. 636-A at p.30,647.

202. This order constitutes such appropriate notice under the Natural Gas Act as may be necessary to the public, including all current and future shippers, that the Commission expects to take appropriate steps in the future to ensure that the pipelines have an opportunity to recover any unrecoverable GSR costs allocated to IT service.

interruptible transportation bears only one such assessment, would give an undue competitive advantage to the marketing of interruptible transportation.

c. Recovering a higher percentage of GSR costs from IT, or all GSR costs through a surcharge on all throughput

Gas Consumers advocate the reduction or elimination of transition costs to firm transportation customers, particularly small customers, and reallocation to producers and interruptible customers, the primary beneficiaries of the restructuring. Gas Consumers argue that a portion of *all* transition costs, not just GSR costs, should be allocated to interruptible transportation customers, and that the allocation should be based on the benefit received by allocating transition costs on the basis of throughput or some other method that assigns costs based on benefits rather than an arbitrary percentage.

New Jersey Natural contends that the Commission erred by failing to allocate 50 percent of the GSR costs to interruptible transportation service, commensurate with the benefits interruptible customers have received from pipeline restructuring.

Peoples Gas argues that transition costs should be allocated to interruptible transportation (as well as all other) customers volumetrically on a *pro rata* basis to reflect more accurately their use of pipeline services and the improved quality of service that the Commission intends for all customers to receive in the future. The Commission's decision to require the allocation of only 10 percent of the GSR costs is improper and unreasonable, according to Peoples Gas, because end-use customers getting their gas delivered through interruptible transportation were

probably all sales customers of pipelines or LDCs when the pipeline contracts giving rise to the GSR costs were entered into, and interruptible transportation customers are presently a major customer group on the pipeline systems, and the most likely beneficiaries of the restructuring rules.

Western Resources argues that allocation of GSR costs should have been left to individual proceedings. According to Western Resources, recovery of 10 percent of the GSR costs from interruptible transportation service is not enough on Williams' pipeline system, and the Commission erred by so limiting the recovery of such costs.

The task of determining fair allocations of transition costs is ultimately thankless, even though we bring all our experience and best judgment to bear on it. The Commission has already considered and rejected the arguments against *any* allocation of GSR costs to interruptible transportation service. The Commission will also reject the requests to require the allocation of *more* GSR costs to interruptible transportation service and to allocate such costs on a volumetric basis. As the Commission explained in Order No. 636-A, assessing 10 percent of the transition costs to interruptible rates will be a short term feature of the pipeline's rates and is a reasonable trade-off in light of the rule's long term benefits.[203] Thus, a 10 percent allocation of GSR costs to interruptible transportation customers is a reasonable accommodation of the many factors and interests at issue here.[204] As the United States Supreme Court has stated,

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203. Order No. 636-A at p. 30,647.

204. *See* Christian Broadcasting Network, Inc. v. Copyright Royalty Tribunal, 720 F.2d 1295, 1304 (D.C. Cir. 1983)(choice of a particular percentage allocation not reviewable for exact precision, but simply for rationality).

"[a]llocation of costs is not a matter of the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[205]

The provisions of Order Nos. 636 and 636-A on allocation of transition costs are not incorporated in the regulations, but are policy statements. The Commission will review specific proposals for recovering transition costs with reference to the particular circumstances of each pipeline system and the degree of support those proposals enjoy from the affected parties.

d. Use of a surcharge vs. allocating GSR costs to interruptible transportation

LILCO states that the Commission erred by requiring pipelines to *allocate* 10 percent of their GSR costs to interruptible transportation service instead of recovering such costs through a *surcharge* on interruptible transportation. According to LILCO, pipelines will simply reduce the costs that they would otherwise allocate to interruptible service by an amount sufficient to offset the allocated GSR costs, so that interruptible customers will not in fact pay any GSR costs, and rates to firm transportation shippers will not be any lower. Furthermore, LILCO asserts, if pipelines adopt a crediting method of accounting for interruptible transportation revenues, firm transportation customers will be deprived of any credit for the GSR costs allocated to interruptible service, and will thus be paying those costs indirectly.

The Commission will deny LILCO's request for rehearing. Ten percent of a pipeline's GSR costs must be *allocated* to the

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205. Colorado Interstate Co. v. FPC, 324 U.S. 581, 589 (1945).

rates for its interruptible service, and may not be recovered through a surcharge. Although LILCO makes the valid point that the allocation of GSR costs to a service with rates determined by competitive forces may not necessarily affect the rates they charge, the allocation of GSR costs increases the maximum rates for interruptible transportation, and service provided at the maximum rates will recover more costs than service at maximum rates without the allocation. Whether GSR costs are directly allocated to interruptible transportation service or recovered by means of a volumetric surcharge on interruptible rates would not alter the effect of competition on discounted transportation rates. The Commission will consider the fairness of a pipeline's proposed allocation of costs to interruptible and firm service, or the fairness of any proposed mechanism for crediting revenue from interruptible service to firm transportation customers, on a case-by-case basis.

e. True-up mechanisms to ensure recovery of GSR costs allocated to interruptible transportation service

Arcadian states that the Commission erred in authorizing true-up mechanisms to recover gas supply realignment costs allocated to interruptible transportation service. Arcadian argues that a true-up mechanism, which would assure a pipeline that any GSR costs not recovered through interruptible transportation rates in one period would be recovered in subsequent periods, would create the same problems as revenue crediting, by eliminating incentives for a pipeline to market interruptible services, and conflict with the Commission's primary aim of improving the competitive structure of the natural gas industry.

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As noted above, in Order No. 636-A, the Commission stated that it does not intend for the pipelines to absorb any portion of the GSR costs and encouraged the pipelines and the parties to the restructuring proceedings to be creative in fashioning rate mechanisms, such as an appropriate true-up mechanism, that provide a reasonable opportunity for pipelines to recover those costs.[206] Putting a pipeline "at risk" of not recovering those costs by requiring it to assign a certain amount of GSR costs to the rate for each unit, on the basis of an estimated level of interruptible transportation volumes, might increase the pipeline's incentive to provide interruptible transportation at the estimated level. However, such a policy would not necessarily improve the pipeline's ability to market the estimated level of interruptible service or provide a reasonable opportunity to recover the assigned GSR costs.

2. Recovery of Costs in Account No. 191 Accrued Before July 31, 1991

INGAA advocates allowing direct billing through the PGA mechanism of pre-July 31, 1991 costs in pipelines' Accounts No. 191. According to INGAA, the Commission's analysis of the issue in Order No. 636-A overlooked the fact that there are still unrecovered gas costs which accrued prior to July 31, 1991, that will be outstanding upon compliance with Order No. 636 and termination of the PGA mechanism. INGAA asserts that pipelines with such costs may not have an ample opportunity to recover them in the last remaining PGA periods, because pre-July 31, 1991 underrecoveries would not normally be recovered until the 1993 PGA year. INGAA asserts that the Commission needs to specifically provide a mechanism for

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206. Order No. 636-A at p.30,647.

recovery of these prudently incurred costs which would have, until the issuance of Order Nos. 636 and 636-A, been fully recoverable under the PGA rules. INGAA also states that the Commission should provide for a waiver of the PGA regulations and allow the pipeline to include all such costs in its demand charge during the final PGA period.

CNG states that the Commission's conclusion that pipelines will have an ample opportunity to recover their pre-July 31, 1991 costs before they terminate their PGA mechanisms is wrong. CNG asserts that the Commission has twice rejected CNG's requests to obtain demand charge treatment for the recovery of Texas Eastern's GSIRC charges, and has instead required CNG to recover those amounts in its commodity surcharge. CNG asserts that, as a result, it has accumulated significant amounts in its Account No. 191 that would be difficult to recover under the normal operation of the PGA mechanism.[207]

Columbia requests clarification that Order No. 636-A does not preclude recovery of pre-July 31, 1991 gas costs if a pipeline can show that there are valid reasons why such costs have not been recovered via the PGA mechanism. Columbia states that it has not, as yet, made certain payments to its gas suppliers relating to its gas purchases during periods preceding its bankruptcy filing and cannot do so absent an appropriate order of the Bankruptcy Court. Columbia predicts that such an order will not be issued in time for such costs to be recovered prior to the elimination of its PGA.

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207. *See* CNG Transmission Corporation, 61 FERC ¶ 61,156 (1992)(Commission accepted tariffs, subject to refund and further review, to accelerate recovery of CNG's Account No. 191 balances and thereby minimize transition costs upon restructuring.)

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Natural urges the Commission to acknowledge that particular situations may arise which require a case-by-case examination of the PGA recovery issue. Natural states that its PGA was suspended as of December 1, 1990, under its Gas Inventory Demand Charge (GIDC) procedures, and that while certain amounts collected pursuant to the GIDC have been applied to recovery of the PGA balance, Natural expects that, absent a further settlement, some balance will remain as of the date Order Nos. 636 and 636-A are fully implemented on its system.[208]

PSE&G requests clarification that any pre-July 31, 1991 costs in Account No. 191 not recovered before termination of a pipeline's PGA must be absorbed by the pipeline.

UtiliCorp Divisions request the Commission to grant rehearing on its treatment of Account No. 191 balances, which UtiliCorp Divisions characterize as in essence an adoption of a FIFO (first-in, first-out) method for determining whether accumulated balances have been eliminated. According to UtiliCorp Divisions, Commission statements in Order No. 636-A imply that a pipeline may attribute *all* of its recovery of gas costs under its PGA mechanism to reduction of its unrecovered balanced accrued before July 31, 1991 — even during periods when unrecovered balances are increased — and argues that such an accounting method would permit pipelines to circumvent the filed rate doctrine.

The Commission recognizes that, due to various specific

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208. *See* Natural Gas Pipeline Company of America, 61 FERC ¶ 61,238 (1992) (order approving settlement on, *inter alia*, past PGA balances and underrecoveries of GIDC costs).

circumstances, such as those described above, some pipelines will not be able to recover all of their unrecovered purchased gas costs that had accrued before July 31, 1991, under the normal application of the regulations, before they terminate their PGA mechanisms upon implementation of restructuring. Therefore the Commission will give serious consideration to petitions for waiver of provisions of the regulations, *e.g.*, the provisions regarding the FIFO method, if necessary to afford pipelines a reasonable opportunity to recover their pre-July 31, 1991 costs before the termination of their PGA mechanisms. Although the Commission will be flexible in the application of the PGA regulations in order to enable the pipelines to recover the costs in Account No. 191, the Commission cannot permit radical departures from the principles upon which the PGA regulations are based.[209]

Waivers of the technical provisions of the PGA regulations may not be sufficient, however, to afford some pipelines a reasonable opportunity to recover all of their pre-July 31 costs, and some pipelines may be unable to recover those costs prior to termination of their PGAs. The Commission will consider creative proposals developed by pipelines to enable them to recover their costs[210] that do not run afoul of the filed rate doctrine.

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209. *See, e.g.*, Carnegie Natural Gas Company, 60 FERC ¶ 61,225 (1992) (Commission denied Carnegie's request for waiver of the regulations to suspend its surcharge rates and to offset its commodity surcharge balance with demand refunds); and CNG Transmission Corporation, 60 FERC ¶ 61,227 (1992) (Commission denied a request for a waiver of the regulations to defer recovery of a portion of surcharge balance and to use refunds to offset that balance).

210. *See, e.g.*, CNG Transmission Corp., 61 FERC ¶ 61,156 (1992) (permitting sale of gas from storage inventory).

The Commission also encourages the pipelines and their customers to enter into settlements to resolve the recovery of any remaining Account No. 191 balances. Accordingly, the Commission will clarify and expand its prior policy to allow proposals from pipelines for special billing mechanisms to recover such costs, and will consider the merits of their proposals on a case-by-case basis. These proposals should be filed as part of the pipeline's restructuring compliance filing. By inviting these proposals, however, the Commission has no intent to be so flexible as to permit a delay in the implementation of the unbundling requirement.

3. Eligibility of Costs for 100 Percent Recovery as GSR Costs

a. Eligibility to recover GSR costs incurred outside restructuring

CNG argues that the Commission should grant clarification to permit pipelines to recover as transition costs those GSR costs, whenever incurred, that are reasonably related to the pipeline's implementation of Order No. 636. CNG wants the Commission to authorize pipelines to engage in the process of reforming their contracts immediately, even before their customers make final decisions concerning their sales entitlements. Furthermore, CNG does not want the Commission to impose deadlines on the recovery of GSR costs. CNG argues that if a producer-supplier knows that the pipeline will be unable to recover its GSR costs unless a settlement is reached by a certain date, the producer-supplier will be unwilling to negotiate.

INGAA objects to the Commission's statement in Order No. 636-A that the use of a surcharge on transportation rates to

recover GSR costs will be limited to such costs that arise as a result of customers' decisions as a result of the restructuring proceedings, and that if customers reduce or terminate their sales entitlements upon expiration of their contract terms after restructuring, the costs of any further gas supply realignments would only be recoverable through market-based sales rates.[211] INGAA requests the Commission to clarify that the mechanism to recover gas supply realignment costs will be applicable to all prudently incurred costs resulting from pipelines having to reform to market levels, or terminate altogether, their existing supply contracts with producers, even if these costs arise outside of the formal restructuring period.

Tenneco requests the Commission to clarify that pipelines may realign contracts prior to implementation of their restructured services. Tenneco notes the Commission's statement in Order No. 636-A that "[i]f all customers terminate their sales entitlements during restructuring, a pipeline may have to buy out all of its gas supply contracts. . . ,"[212] and seeks clarification that this statement does not, by implication, prohibit pipelines from realigning contracts *prior to* implementation of their restructured services. Tenneco asserts that early contract realignment will help to reduce transition costs.

K N seeks clarification that sales customers whose contracts expire after restructuring remain liable for GSR costs. K N states that it does not believe that current sales customers whose contracts will expire in the near future are allowed under Order Nos. 636 and 636-A to escape gas supply realignment costs by

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211. Order No. 636-A at p. 30,649.

212. *Id.* at p. 30,657.

requiring that K N remain in the merchant role only for the duration of their current contract, and then escaping without any gas supply costs responsibility.

The Commission denies rehearing of the eligibility issues raised in the rehearing petitions. As the Commission explained in Order Nos. 636 and 636-A, a pipeline's costs of realigning gas supply contracts are eligible for recovery if these costs are attributable to the implementation of Order No. 636.[213] The costs eligible for recovery are limited to costs that arise as a result of sales customers' decisions during the restructuring proceedings either to reduce or terminate their gas supply obligations with the pipeline.[214] In their compliance filings, pipelines must propose a mechanism for recovery of these costs.

The determination of whether specific costs are attributable to the implementation of Order No. 636 will have to be decided on the basis of the specific facts. Pipelines do not have to delay entering into negotiations to realign their gas supply contracts until after their customers have made final choices during the course of the restructuring proceedings in order for the costs of those realignments to be eligible for the special billing mechanisms for GSR costs under Order No. 636.[215] However, a pipeline may not retain contracts to provide gas

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213. Order No. 636 at p. 30,459.

214. Order No. 636-A at p. 30,649.

215. Enron requests clarification that the definition of GSR costs includes costs resulting from pipelines having to reform to market levels, or terminate altogether, their existing supply contracts with producers. The Commission grants this request. Both such costs are included.

sales in a competitive market and then seek recovery for any further realignment of those contracts that may become necessary. As the Commission stated in Order No. 636-A, pipelines continuing to engage in a merchant function after restructuring are free to set the prices and terms for those contracts, but, by the same token, must bear the risk of their decisions and provide for further realignment in their gas supply agreements.[216]

Enron asserts error in the Commission's statement that Order No. 636 was not intended to affect the provisions of existing settlements resolving transition costs. Specifically, Enron cites the Commission's decision in *Florida Gas Transmission Company*[217] that the costs of certain take-or-pay settlements entered into in December 1991 and January 1992, and subject to the provisions of Florida Gas' transition cost recovery (TCR) mechanism, could not be eligible for recovery as GSR costs under Order No. 636. Enron argues that the Commission improperly established a "bright line" test for eligibility, without giving Florida Gas an opportunity to show that the issuance of the NOPR in this proceeding had significantly altered the circumstances under which Florida Gas had agreed to its TCR mechanism, and had caused the incurrence of the gas supply realignment costs in question.

The Commission will not address case-specific applications of its rule in this generic proceeding, but will address these issues in specific cases. The Commission has already rejected Florida Gas' arguments on rehearing for allowing it further

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216. Order No. 636-A at p. 30,649.

217. 59 FERC ¶ 61,413 (1992).

opportunity to establish the eligibility for recovery of the costs in question as Order No. 636 transition costs.[218]

CIG asks for clarification that the GSR cost recovery mechanism can be utilized in connection with the realignment of producer contracts that extend beyond the term of existing sales contracts. The Commission grants the requested clarification. Prior to Order No. 636, pipelines' service obligations to their sales customers extended beyond the expiration of their sales contracts with those customers. Thus, the fact that the terms of gas supply contracts to be realigned extend beyond the terms of an existing pipeline's sales contracts has no bearing on the eligibility for recovery of the costs of realigning those contracts as transition costs under Order No. 636.

b. Eligibility for recovery of GSR costs by pipelines with GIC mechanisms

Enron seeks clarification that a pipeline is not precluded from seeking to recover GSR costs where a pipeline has utilized a GIC mechanism. It seeks assurance that the Commission will consider, on a case by case basis, the ability of the pipeline to recover GSR costs through the Order No. 636 mechanism. ANR requests clarification that it will be permitted to recover its GSR costs through an Order No. 636 recovery mechanism

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218. *Id.*, 61 FERC ¶ 61,016 (1992). The Commission also will not address, in this proceeding, UGI's arguments on rehearing that the Commission should not allow Columbia to retain the benefits from the "Global Settlement" and prior agreements while freeing them from the risk assumed relating to contract management, and UGI's request for a ruling that Columbia may not recover contract rejection costs arising from its bankruptcy.

notwithstanding its implementation of a GIC charge for an interim period under a recently approved rate case and restructuring settlement.

The Commission reiterates that gas supply costs for which GIC charges have been collected cannot be recovered again as transition costs.[219] However, a pipeline may incur GSR costs as a result of its customers' actions under Order No. 636 that could not have been anticipated in designing the GIC and cannot be recovered through a GIC. The Commission will consider, on a case-by-case basis, whether the gas supply realignment costs attributable to an Order No. 636 restructuring of a pipeline with a GIC are eligible for recovery through the special billing mechanism of Order No. 636.

PGT requests clarification that a pipeline that establishes cost-based rates for its unbundled sales service will continue to be eligible for recovery of prudently incurred gas supply realignment costs under Order No. 636 or Order No. 528.[220] Initially, the basis of a pipeline's rates for its unbundled sales of gas is not relevant to its eligibility to recover take-or-pay costs under Order No. 528 or gas supply realignment costs under Order No. 636. As noted earlier, the basis for establishing the price for unbundled gas sales is a matter between the pipeline and its customers. The recovery of gas supply costs, including any costs of contract reformation after restructuring, must be

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219. Order No. 636-A at p. 30,654. The Commission prohibits a pipeline with a GIC mechanism in place from filing under Order No. 528 to recover take-or-pay costs.

220. The term "gas supply realignment costs" is applicable to transition costs incurred as a result of restructuring under Order No. 636, but not to take-or-pay buyout or buydown costs recoverable under Order No. 528.

negotiated by the parties. How the price under a particular unbundled sales contract is based will be a contractual, not a regulatory matter.

c. Prudence

Northern Indiana questions the Commission's statement in Order No. 636-A that downstream pipelines should not have to absorb any of the transition costs billed to them by upstream pipelines, and advocates holding downstream pipelines to the same standards of prudence review of transition costs as any other costs. The Commission is not requiring any pipelines — upstream or downstream — to absorb transition costs under Order No. 636. However, just as upstream pipelines are subject to challenges to their prudence with regard to incurring transition costs, the Commission clarifies that downstream pipelines will also be subject to such challenges in connection with passing through transition costs billed to them by upstream pipelines. The transition costs incurred by the downstream pipelines as a result of implementing this rule are like any other costs incurred by the pipelines, and nothing in this order is intended to preclude a challenge to their prudence.

CNG questions the Commission's statement in Order No. 636-A that the added presumption of prudence afforded to costs filed for recovery under Order Nos. 500 and 528 does not apply to GSR costs, and seeks clarification that the incurrence of GSR costs is presumptively prudent. CNG urges the Commission to reaffirm the established policy that a pipeline does not bear the burden of proving its prudence unless another participant introduces evidence that creates a serious doubt about the pipeline's prudence. The Commission clarifies that it has not changed the established burden of proof. The Order Nos. 500

and 528 special presumption of prudence, based on a percentage absorption of costs, does not apply to GSR costs.

Gas Consumers assert that prudence reviews do not sufficiently protect small customers. They also assert that if pipelines attempt to recover non-restructuring costs as transition costs, the practical burden is on the customers to prove the imprudence of those costs not associated with Order No. 636. Gas Consumers argue that the Commission should shift the initial burden of going forward on prudence to the filing pipeline and provide better guidance on what constitutes recoverable GSR costs under restructuring.[221]

The Commission will continue to develop policies and guidelines on defining what costs are eligible for treatment as GSR costs as issues arise. Pipelines have the burden of establishing that such costs are eligible for the special billing mechanisms under Order No. 636. As stated above, the special presumption of prudence under Order Nos. 500 and 528 do not apply, but customers will have the burden of presenting evidence that costs that would otherwise be eligible for such billing mechanisms cannot be recovered because they were not prudently incurred.

Cincinnati Gas argues that the Commission's decision to preclude prudence challenges to previously approved cost-recovering mechanisms under Order Nos. 500 and 528 cannot be fairly applied in the circumstances on the Columbia system. Cincinnati Gas requests the Commission to clarify that Columbia's customers and the affected state commissions will

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221. CNG also requests guidance as to identification of the kinds of costs that constitute GSR costs.

be permitted to challenge the prudence of the company's pre-Order No. 636 reformation costs in any proceeding involving the flowthrough of GSR costs. Cincinnati Gas also argues that the Commission should allow challenges to Columbia's prudence under the global settlement if its GIC is terminated. The Columbia-specific issues will be resolved in the appropriate proceeding concerning Columbia's GSR costs on the basis of the unique facts in that proceeding.

CNG states that the Commission should not presume that a pipeline's failure to exercise a "FERC-out" clause would be imprudent. CNG contends that the Commission should also assist pipelines by providing guidance on the propriety of exercising rights under a "FERC-out" clause. Specifically, CNG asks if any aspect of Order No. 636 has the effect of preventing a pipeline from recovering, as part of the pipeline's cost of service, the full amounts paid for natural gas, asserting that many of its gas purchase contracts contain a provision like this. Or do the provisions in Order No. 636 that permit pipelines to recover GSR costs mean that pipelines cannot rely on such contract language to excuse payment of the full contract price? CNG asserts that, without Commission guidance on this issue, litigation will arise in a host of jurisdictions and produce inconsistent interpretations of the Commission's intentions.[222]

The Commission did not establish any presumption of imprudence by a pipeline that fails to exercise a "FERC-out" clause. Nor will the Commission resolve questions about a pipeline's rights under particular provisions in a gas supply contract. First, the Commission's jurisdiction over producer

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222. CNG also raises this same question in a petition for declaratory order filed on October 16, 1992, in Docket No. RP93-12-000.

supply contracts is limited to only a very few contracts, and will be completely abolished as of January 1, 1993, under the provisions of the Natural Gas Wellhead Decontrol Act of 1989.[223] Furthermore, even if the Commission had jurisdiction over certain contracts in the days remaining before January 1, it would defer resolution of contract interpretation questions of the kind raised by CNG to state or federal courts. Under *Pennzoil Co. v. FERC*,[224] the Commission would be required to apply the applicable substantive state law to interpretation of such contracts, so an effort at Commission interpretation would not necessarily achieve the uniformity that CNG advocates.[225]

UtiliCorp Divisions objects to the Commission's statement in Order No. 636-A that it does not intend downstream pipelines to absorb any of the transition costs billed to them by upstream pipelines and the Commission's allowance of mechanisms in downstream pipelines' restructuring compliance filings to flow through those costs. UtiliCorp Divisions argues that such a policy violates the Commission's general policy against cost trackers and fails to provide an incentive for pipelines to vigorously contest both the prudence of the upstream pipeline in incurring such costs and the allocation of those costs to the downstream pipeline.

One-hundred percent recovery of Order No. 636 transition costs billed to downstream pipelines by upstream pipelines is consistent with the Commission's policy permitting such

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223. Pub. L. No. 101-60, 103 Stat. 157 (1989).

224. 645 F.2d 360 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982).

225. In view of this ruling on CNG's request for rehearing, its petition for declaratory order will also be denied for these reasons.

recovery of take-or-pay settlement costs under Order No. 528. Permitting the use of some form of tracking mechanism for such passthrough is reasonable in view of the nature of the costs, although the details of the recovery mechanism must permit reasonable opportunities for interested parties and the Commission to review and challenge the prudence of the costs.

4. Transportation Contracts at Fixed Rates or Discounts.

Enron objects to the Commission's statement in Order No. 636-A that "[i]f a pipeline agreed to provide transportation service at a fixed rate, without a right to passthrough any surcharges or other cost increases, then the pipeline will have to bear the costs of the bargain it made."[226] Enron contends that pipelines should be allowed to recover transition costs from customers with existing transportation service agreements containing fixed rates, discounts, or caps. Enron argues that pipelines could not have anticipated the transition brought about by Order No. 636 and the resulting transition costs, and that denial of relief from their fixed rate contracts is directly contrary to the assurances of Order No. 636 that pipelines could recover 100 percent of all prudently incurred transition costs.

Williston asserts that a pipeline may have entered into fixed rate transportation contracts with firm transportation customers that are not former sales customers, and may have been willing to accept the risk of underrecovery from these customers of a portion of the costs contemplated under Order Nos. 500 and 528, but that the sweeping restructuring mandated by Order No. 636 has fundamentally changed the assumptions on which

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226. Order No. 636-A at p. 30,662.

these agreements were based. Williston also objects to the Commission's rejection of the suggestion that pipelines be allowed to recover transition costs from other customers, or during later periods, when they are unable to fully recover such costs due to the need to discount transportation rates. According to Williston, the Commission's policy simply denies recovery of a portion of a pipeline's prudently incurred transition costs, despite general statements to the contrary.

Natural argues against the requirement of allocating GSR costs to transportation under fixed rates or discounted arrangements negotiated before issuance of Order No. 636-A. Natural states that it has had to offer discounts or enter into fixed rate contracts, and that allocation of transition costs to these contracts would, absent some alternative recovery mechanism, preclude Natural from recovering transition costs in direct contravention of the Commission's stated intent. According to Natural, it had no basis, at the time the agreements were negotiated, to anticipate that such arrangements would subject it to absorption of transition costs.

Natural also objects to requiring the allocation of transition costs to *future* discounted or fixed rate transportation agreements. Natural asserts that parties require a reasonable level of rate certainty to enter into firm transportation arrangements, and that since the transition costs a shipper may have to bear are not well defined, pipelines and shippers will be reluctant to enter into new contracts. Certain firm transportation arrangements will simply not bear the additional burden of transition costs, according to Natural, and the Commission's policy will distort the market for, and economics of, firm transportation.

The Commission clarifies that its statements in Order No.

636-A were not intended to apply a different standard to pipelines that offered discounts pre-restructuring. The Commission's policy is that pipelines will be permitted to recover 100 percent of their prudently incurred gas supply realignment costs that result from compliance with Order No. 636.[227] In their compliance filings, pipelines may propose methodologies to ensure their ability to recover their prudently incurred GSR costs given the individual circumstances on their systems, including discounted transportation provided pre-restructuring. Pipelines choosing to offer discounted firm transportation in the future, however, do so at the risk of not being permitted to recover GSR costs associated with those contracts.

5. Stranded Costs

CNG urges the Commission to provide guidance on the recoverability of stranded costs. Specifically, CNG wants to know whether the cost of facilities no longer needed to render restructured services — unused gathering facilities, production area stubs and laterals, non-productive assets, and any unrecovered purchased gas costs — are recoverable as stranded costs. CNG contends that after restructuring is complete and unbundled services begin, customers will challenge both the eligibility and prudence of the pipeline's transition costs. CNG states that few pipelines will be willing to risk the incurrence of costs that might arguably, for want of guidance, be challenged as ineligible stranded costs.

To be a "stranded cost," the item must no longer be "used or useful" after restructuring. To qualify for 100 percent recovery under Order No. 636, the facilities must have been rendered no

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227. Order No. 636 at p. 30,460.

longer used or useful as a result of the pipeline's compliance with the order. The Commission will consider issues concerning the eligibility for recovery of any claimed stranded costs in the proceedings where pipelines seek to recover such costs. However, once a pipeline's costs have been determined eligible for recovery as stranded costs, the pipeline may not subsequently seek recovery of those costs as an element of its cost of service in any future rate proceeding without recognition of the costs it has recovered as stranded costs.

Among the costs that are potentially eligible for recovery as stranded costs are the costs of capacity on upstream pipelines and upstream storage (Account No. 858 and 824), storage facilities, production facilities, products extraction facilities, gathering facilities, and transmission facilities. This list is not exhaustive and other costs will be considered on a case-by-case basis.

6. Miscellaneous

a. Exit Fees

CNG requests authorization to direct bill customers departing the system for their share of the GSR costs, if the customer refuses to agree to a negotiated exit fee. CNG argues that by declining to allow the unilateral imposition of an exit fee or a direct bill on departing customers, the Commission has substantially undercut the pipeline's ability to have the departing customer bear its fair share of the GSR costs. Furthermore, CNG argues that a departing customer's refusal to pay an exit fee will cause remaining customers to shoulder an increasing burden of the GSR costs. Williston also argues that the Commission's prohibition in Order No. 636-A of a unilateral imposition of

exit fees on a customer that is reducing or terminating sales, but is not reducing its reservation of transportation capacity, deprives pipelines of a legitimate vehicle for cost recovery.

The Commission clarified in Order No. 636-A that it was not authorizing the unilateral imposition of exit fees on customers that are reducing or terminating gas purchases from the pipeline, but not departing the system as transportation customers. As long as a customer remains on the system as a firm transportation customer of the pipeline, the pipeline can recover a portion of its GSR costs through the surcharge on that customer's transportation rates. Pipelines and their customers may negotiate exit fees in lieu of, or in combination with, a surcharge on reservation fees for recovering GSR costs. The Commission strongly encourages this.[228] A customer may also negotiate the payment of an exit fee for a release from its obligation to pay for firm transportation capacity, and thus depart the system altogether. But, absent such a negotiated exit fee, the Commission will not require customers to pay exit fees or permit them to be direct billed for the recovery of GSR costs.

b. Limited section 4 filings to recover transition costs

UtiliCorp Divisions also objects to the Commission's clarification in Order No. 636-A (which UtiliCorp Divisions contends is a change in position rather than a clarification) that pipelines may file to recover GSR costs and to direct bill

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228. If a customer leaves the system as a transportation customer *before* its contract expires, the pipeline will be in a posistion to charge that customer an exit fee since the early (and valid) termination of the contract can only be accomplished by mutual agreement by the pipeline and shipper.

Appendix D

Account No. 191 balances in limited section 4 proceedings. UtiliCorp Divisions argues that the Commission's actions here contrast, without reasoned basis, with its prior rulings barring transition cost trackers in the context of gas inventory costs charges by an upstream pipeline to a downstream pipeline. UtiliCorp Divisions contends that only if all costs are considered in one proceeding, both those which have increased and those which have decreased, can the Commission be assured that the overall rates charged customers are reasonable as required by the NGA.

Unrecovered Account No. 191 balances and GSR costs may be recovered through one-time-only or short-term charges that are not necessarily related to a pipeline's ongoing patterns of revenues and expenses. Accordingly, there is no particular benefit in reviewing the amounts or eligibility for recovery of these costs, along with all of the pipeline's other costs, in the context of a general section 4 rate case. Moreover, the details of the cost recovery mechanisms will have been resolved in the restructuring proceedings prior to the time limited section 4 filings are made to recover these costs.

Transco requests the Commission to allow limited section 4 filings to recover stranded costs. Transco states that the requirement to use a full-blown section 4 rate case to recover stranded costs is administratively burdensome, because it is predictable that every pipeline will incur stranded costs, and the Commission and interested parties will be inundated with a new major rate case by every restructuring pipeline. According to Transco, stranded costs do not represent new costs, but costs that are currently being collected in rates in a manner that can be expected to change as a result of restructuring, and the requirement of a full section 4 rate filing will deny pipelines

full recovery of transition costs by delaying the implementation of rates to recover costs no longer recovered under restructured rates. There is enough for affected parties to do in the next year, Transco asserts, without imposing the demands of a full-blown general rate proceeding, where a proceeding on a limited section 4 filing would afford a fair examination of the costs at issue.

The Commission will allow pipelines to make limited section 4 filings to recover Account No. 858 costs and the costs of stranded facilities that are currently incrementally priced, such as storage facilities on some pipeline systems. Since these costs are already in the cost of service, they could be recovered through a tracking-type procedure. However, pipelines must file to recover the costs of most, if not all other stranded facilities in general section 4 rate proceedings. A full section 4 proceeding is necessary because of the necessity of determining depreciable plant balances, associated taxes and other direct costs, and appropriate allocations of indirect costs to the stranded items.

c. When can pipelines begin recovery of transition costs?

PSE&G requests clarification that even a limited section 4 filing to recover transition costs must comply with the requirement of section 154.63(e)(2) of the Commission's regulations[229] that any projected estimate of such costs must be known and measurable with reasonable accuracy as of the date of the pipeline's filing.

PSE&G also requests clarification that a pipeline may not

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229. 18 CFR § 154.63(e)(2)(1992).

begin to recover any transition costs, even subject to refund, until such time as the Commission has issued a final order on the merits of the pipeline's compliance filing in which the Commission makes findings that the pipeline is in full compliance with the requirements of Order Nos. 636 and 636-A.

UDC requests that the Commission not allow pipelines to begin recovering potential, estimated transition costs through their compliance filings. UDC states that the Commission should clarify that the pipeline may not recover transition costs from its customers until those costs are actually incurred, unless the parties otherwise agree.

LILCO also requests clarification that GSR costs are only recoverable after they have been incurred, but also requests that if pipelines are allowed to recover estimated (but not yet incurred) GSR costs, interest not be allowed on the unpaid balance of any such estimated costs.

GSR costs must be actually incurred, or known and measurable with reasonable accuracy, in order to qualify for recovery by the pipeline.[230] Pipelines may not begin recovery of any transition costs under Order No. 636, even subject to refund, until after the Commission has found the pipeline to be in full compliance with the requirements of Order Nos. 636 and 636-A. Finally, pipelines will not be permitted to recover interest on the unpaid balance of any estimated GSR costs.

Pipelines should not make filings to begin recovery of their

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230. For purposes of recovering GSR costs, the Commission will consider reasonable variations from the test year requirements utilized in general section 4 rate cases.

GSR costs until after the Commission has approved the recovery mechanisms for such costs included in their restructuring compliance filings. When the Commission rules on a compliance filing, it will specify a prospective date when the tariff sheets implementing restructured services will become effective. Pipelines will then have an opportunity to make a limited section 4 filing to begin recovery of actual GSR costs, under the approved mechanism, contemporaneously with the implementation of the restructured services.

d. Small customers

Tennessee and Columbia Small Customers allege that the Commission erred in Order No. 636-A in refusing to reduce small customers' responsibility for transition costs by 50 percent, consistent with the small customer protection mechanism established in Order No. 528-A. They argue that Order No. 636-A does not go far enough to mitigate the negative impact of Order No. 636 on small customers.

Order No. 636-A significantly modified the final rule to ensure the ability of small customers to secure the benefits of restructuring and to mitigate adverse effects. The additional mitigation of a 50 percent reduction in transition costs for *every* small customer on *every* pipeline system is not warranted. However, pipelines and parties in the restructuring proceedings on particular systems may consider such additional mitigation mechanisms they may agree may be appropriate.

e. Refund provision

NJBRC advocates that there be no interim collection of transition costs, subject to refund. NJBRC argues that, in light

of recent federal court actions in the Columbia bankruptcy proceeding, allowing such recovery prior to a final decision on any challenges to eligibility or prudence will place ratepayers' monies too much at risk. As a general matter, under section 4(e) of the NGA, pipelines are entitled to begin recovering their filed rates, subject to refund, at the end of any suspension period, if the Commission has not rendered a final decision of the justness and reasonableness of the changed rates. Section 4(e) also provides that a pipeline may be required to furnish a bond to ensure the payment of refunds of rate increases collected subject to refund. Parties may petition the Commission to require such a bond where the circumstances might warrant it. The Commission will endeavor to process the filings as quickly as possible (as contemplated by NGA section 4) to try to minimize the length of time rates are collected subject to refund.

f. Direct billing of Account No. 858 costs

LILCO argues that the Commission erred in permitting Account No. 858 transition costs to be direct billed in the same manner as Account No. 191 costs instead of requiring them to be treated like other GSR costs.[231] According to LILCO, prudently incurred, eligible, upstream-pipeline GSR costs incurred by the downstream pipeline are no different from its own GSR costs and should be recovered no differently.

United asserts that in Order No. 636, the Commission classified Account No. 858 costs that could not be directly allocated to customers of unbundled services as "stranded costs." United requests clarification that Order No. 636-A supersedes Order No. 636 on this point, and that pipelines may direct bill Account No. 858 balances to their own customers.

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231. LILCO cites Order No. 636-A at p. 30,655.

Appendix D

Both LILCO and United misconstrue what the Commission said in Order No. 636-A. The Commission addressed an issue raised by National Fuel concerning pipelines with Account No. 858 trackers, namely, how may a pipeline recover an unrecovered positive balance in such a tracking account upon termination of the tracker? Such a situation is precisely analogous to unrecovered balances in Account No. 191 upon termination of a PGA mechanism, and the Commission provided for direct billing of such balances in both situations. The Commission was not authorizing direct billing of upstream pipeline GSR costs or future Account No. 858 costs that become "stranded" in the course of restructuring. How these costs will be recovered will be dealt with on a case-by-case basis.

g. Avoiding multiple GSR charges

Producer Associations argue that short-haul, production-area transportation, and transportation to pooling points and market centers, should be exempt from GSR recovery programs. Otherwise, they argue, transportation arrangements will be subject to multiple assessments of GSR surcharges that will often discourage the use of the most efficient path to market. Producer Associations cite the Commission's policy of not permitting multiple assessments of Gas Research Institute surcharges as precedent for its proposal.

The Commission will not permit exemption of short-haul, production-area transportation, or transportation to pooling points and market centers from GSR surcharges. Such exemptions would frustrate realization of the Commission's goal of spreading transition costs equitably over a broad customer base. However, pipelines and affected parties in the restructuring proceedings should design mileage-sensitive surcharges, so that

shippers that use only a portion of the pipeline do not pay a disproportionate share of surcharges.[232]

h. Default under an assigned supply contract

Enron seeks clarification that the pipeline must be able to negotiate, as part of the terms and conditions of assigning supply contracts to its customers, a means to recover GSR costs attributable to a customer's default under the assigned contract, where the pipeline remains liable to the producer. Otherwise, according to Enron, the pipeline could be in a "catch-22" situation because the customers could take assignment of such contracts and subsequently elect not to perform under such contracts.

In Order No. 636-A, the Commission stated that the details of responsibility for transition costs of customers that accept assignment of gas supply contracts, in comparison with those that do not, must be worked out in the restructuring proceedings.[233] The Commission will consider any reasonable provisions the pipelines and their customers can negotiate to protect the pipeline in the event of a default on an assigned contract.

i. Recovery of GSR costs from rates for storage service

PSE&G seeks clarification that in the absence of any

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232. *See* Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout or Buydown Costs, 54 FERC ¶ 61,095 at p. 61,301 (1991)(Order No. 528-A).

233. Order No. 636-A at p. 30,660.

connection between cost causation and cost incurrence, transition cost surcharges designed to recover GSR costs will not be assessed against storage services, even though storage is now defined as transportation under Part 284. PSE&G argues that there is no connection between a pipeline's incurrence of such costs and its provision of storage service, and that, since storage customers will already be assessed GSR costs in connection with their transportation to and from storage facilities, no additional assessments for storage service are warranted.

Nothing in Order No. 636 or 636-A requires pipelines to impose demand surcharges for the recovery of GSR costs on unbundled storage service. If a pipeline proposes to impose such a surcharge on storage service, it should explain why the surcharge on transportation to and from the storage facility does not recover a fair share of the GSR costs from the storage customers.

j. Great Plains synthetic gas

Northern Natural, Transwestern, and Florida Gas (collectively referred to as Enron) request that Order No. 636-A be clarified to reflect that the costs of the Great Plains Gasification Project may not be allocated to NGA section 7(c) shippers. Enron asserts that section 7(c) customers clearly did not cause or were not benefitted by contracts involving the Great Plains synthetic natural gas. Enron asserts that the Great Plains costs have consistently been treated as gas supply costs, while the section 7(c) customers merely utilized the pipeline for transportation. Enron asserts that, in many instances, these costs will be recovered from customers who did not even utilize the pipeline out of the Great Plains project, and that since the 7(c) transporters neither caused nor benefitted from the Great Plains

project, allocating costs associated with Great Plains to those transporters would only distort the market signals between supply and demand.

In Order No. 636-A, the Commission clarified that it would consider *any* reasonable proposal by the pipelines that purchase Great Plains gas for recovery of the costs of that gas, whether or not modeled on the proposal approved in a Transco settlement.[234] If any of the pipelines that purchase Great Plains gas propose to recover the costs of such gas from transportation rates for service under individual section 7(c) certificates, the Commission will consider any arguments for or against such recovery in the proceeding where the proposal is made.

k. Triennial rate review

New England Power and ConEd assert that the Commission erred by not requiring pipelines to be subject to a three-year rate review. New England Power asserts that the elimination of the triennial rate review requirement allows pipelines, once rates are in place, to sit back and watch their rates of return on equity rapidly escalate, with no corresponding obligation or incentive to refile and reduce their rates. New England Power asserts that unless the Commission institutes remedial measures on rehearing, natural gas consumers will not be sufficiently protected from pipelines' excessive transportation rates. New England Power and ConEd assert that the section 5 complaint procedure is by itself inadequate protection because its remedy is prospective only. Finally, New England Power asserts that the Commission has the authority to require periodic section 4 filings as a condition of some other benefit voluntarily accepted

234. Order No. 636-A at p. 30,658.

by the pipeline. It asserts that the numerous benefits conferred on pipelines by the Order No. 636 regulatory scheme, such as transition cost recovery and SFV rate design, justify imposition of a periodic rate filing requirement.

ConEd asserts that in rejecting requests to maintain the three year rate review, the Commission failed to adequately explain how a change from cost-based to market-based rates reduces the need for periodic Commission review of a pipeline's non-gas rates. ConEd asserts that, as with the PGA mechanism, market-based sales rates similarly provide a pipeline with the opportunity to change only one cost element of its rates outside of a general section 4 rate proceeding. Finally, ConEd asserts that a rate design which virtually assures a pipeline full cost recovery regardless of the actual level or quality of service that it provides, *i.e.*, SFV, cries out for greater Commission oversight, not a relaxation of the current rate review process.

It is unnecessary for the Commission to attempt to replicate the triennial rate review provisions of the PGA regulations when pipelines terminate their PGAs. In any event, there are limits to the authority of the Commission to require pipelines to periodically justify their existing rate levels.[235] However, as the Commission stated in Order No. 636-A, the procedures provided under NGA sections 4 and 5 should ensure that a pipeline's rates are just and reasonable under ordinary circumstances, and the Commission intends to exercise its powers under those sections to the fullest. In circumstances where there are reasonable expectations of declining costs over the long run,

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235. Public Service Commission of New York (PSCNY) v. FERC, 866 F.2d 487 (D.C. Cir. 1989)(requiring periodic filings under NGA section 4 beyond Commission's statutory authority).

ratemaking methods are available to establish rates that will not over-recover those costs.[236] Furthermore, parties may negotiate for a pipeline's agreement to file section 4 rate proceedings periodically, or by a date certain.[237]

l. Filing of Firm Transportation Service Agreements

APGA requests the Commission to amend the regulations to require pipelines to file their firm transportation service agreements with the Commission or make them available to customers, in order to assure that pipelines treat their customers in a non-discriminatory fashion. APGA states that the Commission has, for example, stated that pipleines must offer evergreen provisions on a non-discriminatory basis, but has not provided a means of determining whether the pipleines are complying with this requirement.

The prohibition against discriminatory practices is not a new requirement imposed by Order No. 636, but has always been a requirement under Part 284 of the regulations. The Commission eliminated the requirement that pipelines file copies of their service agreements in 1989[238] and has received no complaints since then, nor is there any basis for concluding

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236. *See* Ozark Gas Transmission System, 50 FERC ¶ 61,252 (1990)(order on remand from PSCNY v. FERC, *supra*), *order on reh'g*, 53 FERC ¶ 61,451 (1990).

237. Ozark Gas Transmission System, 55 FERC ¶ 61,360 (1991).

238. Final Regulations Clarifying the Filing Obligations for Part 284 Transportation and Sale of Natural Gas, FERC Stats. and Regs. [Regulations Preambles 1986-1990] ¶ 30,864.

that a reinstatement of the requirement is necessary to ensure compliance with the prohibitions against discrimination. However, pipelines should make these contracts available upon request so that interested parties can be assured of compliance.

C. Confidentiality of Discovery Data

Rochester filed a motion for clarification of the Commission's June 24, 1992 order in these proceedings relating to the use of discovery procedures in the pipeline restructuring proceedings.[239] Rochester asserts that some pipelines submitting discovery data to the parties and Commission staff have claimed that such material is privileged and confidential pursuant to Rule 602(e)(2) of the Commission's Rules of Practice and Procedure, which provides that an offer of settlement that is not approved by the Commission, and any comment on that offer, is not admissible in evidence against any participant who objects to its admission. Rochester argues that data and material submitted in response to the staff's data requests in restructuring proceedings are not subject to the provisions of Rule 602(e)(2) because they are not offers of settlements or comments on such offers.

The Commission grants the requested clarification. Data and material submitted pursuant to staff data requests in a restructuring proceeding prior to the date the pipeline files its compliance filing are not subject to the provisions of Rule 602(e)(2). Section 388.112 of the Commission's regulations is the relevant provision governing the treatment of material submitted to the Commission under a claim of privilege or confidentiality. Parties may negotiate their own protective

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239. 59 FERC ¶ 61,351 (1992).

agreements regarding information exchanged between the pipelines and parties in the restructuring proceedings. However, the information exchanged in such proceedings is not for the purpose of settlement, but to assure that the pipeline has complied with the Commission's orders.

IX. CONCLUSION

With this order, the Commission ends this rulemaking process. The regulations governing the historic restructuring of the natural gas pipeline industry are now final. No further petitions for rehearing of Order No. 636-B will be considered. The Commission intends now to turn its attention and resources to processing each pipeline's compliance filing as quickly as possible so that gas consumers throughout the nation can begin to realize the competitive benefits of a restructured gas industry.

The Commission orders:

Order Nos. 636 and 636-A, and the June 24, 1992 order in this proceeding, are clarified as set forth in this order, and rehearing of Order No. 636-A is denied.

By the Commission. Commissioner Moler dissented in part with a separate statement attached.

(SEAL)

Lois D. Cashell,
Secretary.

Appendix D

APPENDIX

Allied-Signal, Inc. — (Allied-Signal)

American Gas Association — (AGA)

American Natural Gas Corporation and National Energy Systems Company — (American Natural Gas)

American Paper Institute, Inc. — (American Paper Institute)

ANR Pipeline Company — (ANR)

Arcadian Fertilizer, L.P. - (Arcadian)

Arkla, Inc. - (Arkla)

Associated Gas Distributors — (AGD)

Atlanta Gas Light Company and Chattanooga Gas Company — (Atlanta Gas)

BarClays Bank, PLC, Canadian Imperial Bank of Commerce, Credit Lyonnnais and The Fuji Bank, Ltd. — (Barclays)

Blue Flame Suppliers, Corporation — (Blue Flame)

Brooklyn Union Gas Company — (Brooklyn Union)

Cincinnati Gas & Electric Company, The Union Light, Heat and Power Company, Lawrenceburg Gas Company and Mountaineer Gas Company — (Cincinnati Gas)

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Citizens Gas & Coke Utility — (Citizens Gas)

CNG Transmission Corporation — (CNG)

Colorado Interstate Gas Company (CIG)

Columbia Gas Transmission Corporation — (Columbia)

Consolidated Edison Company of New York, Inc. — (ConEd)

Consolidated Minerals, Inc., Georgia-Pacific Corporation, Rinker Materials Corporation, and U.S. Agri-Chemicals Corporation — (Consolidated Minerals)

East Tennessee Group and The Tennessee Valley Municipal Gas Association — (TVMGA)

Elizabethtown Gas Company — (Elizabethtown)

Florida Municipal Natural Gas Association — (FMNGA)

Fuel Managers Association

Great Lakes Gas Transmission Limited Partnership — (Great Lakes)

Industrial Groups — (Process Gas Consumers Group, American Iron and Steel Institute, Georgia Industrial Group, Association of Businesses Advocating Tariff Equity, California Industrial Group, California Manufactures Association, and California League of Food Processors)

Interstate Natural Gas Association of America — (INGAA)

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Interstate Power Company — (Interstate Power)

JMC Power Projects

K N Energy, Inc. — (K N)

Long Island Lighting Company — (LILCO)

Louisville Gas and Electric Company — (Louisville)

Memphis Light, Gas and Water Division, City of Memphis, Tennessee, Philadelphia Gas Works, and The American Public Gas Association — (APGA)

Meridian Oil Inc. — (Meridian)

Midland Cogeneration Venture Limited Partnership — (Midland Cogeneration)

Missouri Public Service, Kansas Public Service, Michigan Gas Utilities, & Peoples Natural Gas Company, Divisions of UtiliCorp United Inc. — (UtiliCorp Divisions)

Missouri Public Service, Kansas Public Service, & Peoples Natural Gas Company, Divisions of UtiliCorp United Inc. — (Indicated UtiliCorp Divisions)

Mojave Pipeline Company — (Mojave)

Municipal Gas Authority of Georgia

National Association of Gas Consumers — (Gas Consumers)

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National Fuel Gas Supply Corporation — (National Fuel)

Natural Gas Pipeline Company of America — (Natural)

NERCO Oil & Gas, Inc. — (NERCO)

New England Gas Distributors — (New England Gas)

New England Power Company — (New England Power)

New Jersey Board of Regulatory Commissioners — (NJBRC)

New Jersey Natural Gas Company — (New Jersey Natural)

New York State Electric & Gas Corporation — (NYSE&G)

Northeast Energy Associates and North Jersey Energy Associates (Northeast Energy)

Northern Distributor Group

Northern Indiana Public Service Company — (Northern Indiana)

Northern Natural Gas Company (Northern), Transwestern Pipeline Company (Transwestern), and Florida Gas Transmission Company (Florida Gas) — (Enron)

Northern States Power Company and Northern States Power Company — (Northern States)

Pacific Gas and Electric Company — (PG&E)

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Pacific Gas Transmission Company — (PGT)

Pacific Interstate Offshore Company (PIOC)

Pacific Offshore Pipeline Company — (POPCO)

Panhandle Eastern Pipe Line Company, Texas Eastern Transmission Corporation, Algonquin Gas Transmission Company and Trunkline Gas Company — (PEC Pipeline Group)

Peoples Gas Light and Coke Company, North Shore Gas Company and Northern Illinois Gas Company — (Peoples Gas)

Power Authority of the State of New York — (Power Authority)

Prior Energy Corporation — (Prior Energy)

Producer Associations — (Independent Petroleum Association of America, Independent Petroleum Association of New Mexico, Louisiana Association of Independent Producers and Royalty Owners, Ohio Oil & Gas Association, Oklahoma Independent Petroleum Association, and Panhandle Producers and Royalty Owners Association)

Public Service Electric and Gas Company and New Jersey Natural Gas Company — (PSE&G)

Questar Pipeline Company — (Questar)

Rochester Gas and Electric Corporation — (Rochester)

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Sierra Pacific Power Company — (Sierra)

Southern California Edison Company — (SoCal Edison)

Southern Natural Gas Company — (Southern)

Southwest Gas Corporation — (Southwest Gas)

State Regulatory Commissions — (Iowa, Missouri, and Wisconsin) (State Commissions)

Tenneco Gas - (Tennecc)

Tennessee Small General Service Customer Group & the Columbia Small Customer Group — (Tennessee and Columbia Small Customers)

TransCanada Pipelines Limited — (TransCanada)

Transcontinental Gas Pipeline Corporation — (Transco)

UGI Utilities, Inc. (UGI)

United Cities Gas Company — (United Cities)

United Distribution Companies (UDC)

United Gas Pipe Line Company — (United)

Virginia Electric and Power Company — (Virginia Power)

Washington Gas Light Company — (Washington Gas)

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Western Resources, Inc. (Western Resources)

Williams Gas Marketing Company — (WGM)

Williston Basin Interstate Pipeline Company — (Williston)

Appendix D

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM91-11-004

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations

Docket No. RM87-34-069

Regulation of Natural Gas Pipelines After Wellhead Decontrol

(Issued November 27, 1992)

MOLER, Commissioner, *dissenting in part*:

I will not reiterate the points I made in my dissent to Order No. 636-A. However, a new issue is starkly presented to the Commission in this order, and I disagree with how my colleagues have resolved it.

In Order No. 636-A we permitted small customers to continue their historical right to a one-part rate. On rehearing the small customers have pointed out that a right to capacity at a one-part rate on the downstream pipeline does not go far enough. They seek one-part rates all the way to the wellhead. In response to their request, the Commission leaves the issue of small customer rates on upstream pipelines to the vagaries of the restructuring proceedings. I disagree with that approach.

By limiting the right to a small customer rate to customers "directly connected to" a pipeline, the majority has decided in

this order that a small customer may not have access back to the wellhead. Moreover, the upstream capacity may also cost substantially more. This is because the small customer (which has in the past paid Account No. 858 costs as a volumetric charge) may have to pay a two-part rate, with a reservation charge, to get upstream access. I will closely watch how this issue plays out in the restructuring proceedings.

For this reason, I must dissent in part.

Elizabeth Anne Moler
Commissioner

APPENDIX E — *PIPELINE SERVICE OBLIGATIONS AND REVISIONS TO REGULATIONS GOVERNING SELF-IMPLEMENTING TRANSPORTATION UNDER PART 284 OF THE COMMISSION'S REGULATIONS, AND REGULATION OF NATURAL GAS PIPELINES AFTER PARTIAL WELLHEAD DECONTROL*, "ORDER NO. 636-C", *NOTICE OF DENIAL OF REH'G*, 62 F.E.R.C. ¶ 61,007 (1993)

Commission Opinions, Orders and Notices

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

Docket No. RM91-11-005

Docket No. RM87-34-070

62 FERC ¶ 61,007 (1993)

ORDER NO. 636-C

Notice of Denial of Rehearing

(Issued January 8, 1993)

By Direction of the Commission: Lois D. Cashell, Secretary.

In Order No. 636-B, the Commission stated that "[n]o further petitions for rehearing of Order No. 636-B will be considered." Therefore, take notice that the Commission has determined to take no action on the requests for rehearing of Order No. 636-B,[1] filed by Elizabethtown Gas Company,

1. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas (Cont'd)

Appendix E

Piedmont Natural Gas Company, TransCanada PipeLines Limited, Cascade Natural Gas Corporation, Washington Natural Gas Company, and the Washington Power Company, Western Tennessee Municipal Group and Kentucky Cities, Meridian Oil, Inc., UGI Utilities, Inc., Michigan Gas Utilities, Missouri Public Service, Brooklyn Union Gas Company, Kansas Public Service and Peoples Natural Gas Company, Divisions of Utilicorp United, Inc., KN Customer Group, Mississippi River Transmission Corporation, the PEC Pipeline Group (Algonquin Gas Transmission Company, Panhandle Eastern Pipe Line Company, Texas Eastern Transmission Corporation, and Trunkline Gas Company), Long Island Lighting Company, the East Tennessee Group and the Tennessee Valley Municipal Association, Hadson Gas Systems, Inc., Leviathan Gas Pipeline Company, National Fuel Gas Distribution Corporation, the Missouri Public Service Commission, the New England Gas Distributors, and the Associated Gas Distributors.

Accordingly, the requests for rehearing are deemed denied under section 19(a) of the Natural Gas Act[2] and rule 713(f) of the Commission's Rules of Practice and Procedure.[3]

(Cont'd)

Pipelines After Partial Wellhead Decontrol, 57 Fed. Reg. 13,267 (April 16, 1992), FERC Statutes and Regulations P 30,939 (April 8, 1992), reh'g granted and denied in part, Order No. 636-A, 57 Fed. Reg. 36,128 (August 12, 1992), FERC Statutes and Regulations P 30,950 (August 3, 1992), order on reh'g, Order No. 636-B, 57 Fed. Reg. 57,911 (December 8, 1992), 61 FERC P 61,272 (1992).

2. 15 U.S.C. § 717r.

3. 18 C.F.R. § 385.713(f) (1992).

APPENDIX F — *UNITED DISTRIBUTION COMPANIES V. FEDERAL ENERGY REGULATORY COMMISSION*, ORDER MODIFYING OPINION (OCTOBER 29, 1996)

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 92-1485

September Term, 1995

United Distribution Companies,

Petitioner

v.

Federal Energy Regulatory Commission,

Respondent

---

and consolidated cases

Before: WALD, SENTELLE and ROGERS, *Circuit Judges.*

ORDER

It is **ORDERED**, by the Court, on its own motion, that the opinion filed herein on July 16, 1996, is amended, as follows:

At page 72:

Delete footnote 62

and substitute therefor new footnote 62, as follows:

Appendix F

The LDCs briefly argue that NGA § 1(c), the so-called "Hinshaw exemption," deprives the Commission of jurisdiction over their capacity sales to their own end-users. In this regard, they refer us to Congress' determination in § 1(c) that certain pipelines are "matters primarily of local concern and subject to regulation by the several States." 15 U.S.C. § 717(c). For the reasons set out in the text, however, the Commission's authority to regulate capacity release arises from its jurisdiction over the interstate pipeline that consummates the transaction and the subject of the transaction, the interstate transportation of gas, entirely independent of its jurisdiction over the releasing or replacement shipper. Accordingly, we reject the LDCs' claim, given that they do not suggest that FERC has improperly exercised jurisdiction over the release of capacity held on nonjurisdictional Hinshaw pipelines.

Per Curiam
FOR THE COURT:
Mark J. Langer, Clerk

s/ illegible
Deputy Clerk

APPENDIX G — *UNITED DISTRIBUTION COMPANIES V. FEDERAL ENERGY REGULATORY COMMISSION*, ORDER DENYING PETITIONS FOR REHEARING (OCTOBER 29, 1996)

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 92-1485

September Term, 1995

United Distribution Companies,

Petitioner

v.

Federal Energy Regulatory Commission,

Respondent

Windward Energy and Marketing Company, et al.,

Intervenors

Consolidated with 92-1495, 92-1496, 94-1171, 94-1173, 94-1174, 94-1175, 94-1176, 94-1177, 94-1178, 94-1179, 94-1180, 94-1181, 94-1183, 94-1184, 94-1185, 94-1187, 94-1188, 94-1189, 94-1190, 94-1193, 94-1194, 94-1196, 94-1197, 94-1198, 94-1200, 94-1201, 94-1206, 94-1207, 94-1209, 94-1213, 94-1215, 94-1217, 94-1218, 94-1222, 94-1223, 94-1226, 94-1228, 94-1229, 94-1231, 94-1232, 94-1233, 94-1234, 94-1236, 94-1237, 94-1238, 94-1239, 94-1240, 94-1241, 94-1242, 94-1243, 94-1246, 94-1247, 94-1248, 94-1249, 94-1252, 94-1256, 94-1257, 94-1258, 94-1259, 94-1263, 94-1264, 94-1265, 94-1267, 94-1270

Appendix G

BEFORE: Wald, Sentelle and Rogers, Circuit Judges

ORDER

Upon consideration of the petitions for rehearing of the Atlanta Gas Light Company, et al. and Associated Gas Distributors, et al., and of the response thereto, it is

ORDERED that the petitions be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

s/ Robert A. Bonner
Robert A. Bonner

APPENDIX H — *UNITED DISTRIBUTION COMPANIES V. FEDERAL ENERGY REGULATORY COMMISSION*, ORDER DENYING SUGGESTIONS FOR REHEARING *IN BANC* (OCTOBER 29, 1996)

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 92-1485

September Term, 1995

United Distribution Companies,

Petitioner

v.

Federal Energy Regulatory Commission,

Respondent

Windward Energy and Marketing Company, et al.,

Intervenors

Consolidated with 92-1495, 92-1496, 94-1171, 94-1173, 94-1174, 94-1175, 94-1176, 94-1177, 94-1178, 94-1179, 94-1180, 94-1181, 94-1183, 94-1184, 94-1185, 94-1187, 94-1188, 94-1189, 94-1190, 94-1193, 94-1194, 94-1196, 94-1197, 94-1198, 94-1200, 94-1201, 94-1206, 94-1207, 94-1209, 94-1213, 94-1215, 94-1217, 94-1218, 94-1222, 94-1223, 94-1226, 94-1228, 94-1229, 94-1231, 94-1232, 94-1233, 94-1234, 94-1236, 94-1237, 94-1238, 94-1239, 94-1240, 94-1241, 94-1242, 94-1243, 94-1246, 94-1247, 94-1248, 94-1249, 94-1252, 94-1256, 94-1257, 94-1258, 94-1259, 94-1263, 94-1264, 94-1265, 94-1267, 94-1270

Appendix H

BEFORE: Edwards, Chief Judge; Wald, Silberman, Williams, Ginsburg, Sentelle, Henderson, Randolph, Rogers and Tatel, Circuit Judges

ORDER

Upon consideration of the Suggestions for Rehearing *In Banc* of the Atlanta Gas Light Company, et al, and of Associated Gas Distributors, et al., the response thereto, and the absence of a request by any member of the court for a vote, it is

ORDERED that the suggestions be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

s/ Robert A. Bonner
Robert A. Bonner
Deputy Clerk

Circuit Judges Silberman and Henderson did not participate in this order.

APPENDIX I — SECTION 1 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717 (1994)

15 U.S.C.A. § 717

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B — NATURAL GAS

§ 717. Regulation of natural gas companies

(a) Necessity of regulation in public interest

As disclosed in reports of the Federal Trade Commission made pursuant to S.Res. 83 (Seventieth Congress, first session) and other reports made pursuant to the authority of Congress, it is declared that the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest.

(b) Transactions to which provisions of chapter applicable

The provisions of this chapter shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and

to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

(c) Intrastate transactions exempt from provisions of chapter; certification from State commission as conclusive evidence

The provisions of this chapter shall not apply to any person engaged in or legally authorized to engage in the transportation in interstate commerce or the sale in interstate commerce for resale, of natural gas received by such person from another person within or at the boundary of a State if all the natural gas so received is ultimately consumed within such State, or to any facilities used by such person for such transportation or sale, provided that the rates and service of such person and facilities be subject to regulation by a State commission. The matters exempted from the provisions of this chapter by this subsection are declared to be matters primarily of local concern and subject to regulation by the several States. A certification from such State commission to the Federal Power Commission that such State commission has regulatory jurisdiction over rates and service of such person and

facilities and is exercising such jurisdiction shall constitute conclusive evidence of such regulatory power or jurisdiction.

(d) Vehicular natural gas jurisdiction

The provisions of this chapter shall not apply to any person solely by reason of, or with respect to, any sale or transportation of vehicular natural gas if such person is—

(1) not otherwise a natural-gas company; or

(2) subject primarily to regulation by a State commission, whether or not such State commission has, or is exercising, jurisdiction over the sale, sale for resale, or transportation of vehicular natural gas.

APPENDIX J — SECTION 2 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717a (1994)

15 U.S.C.A. § 717a

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B—NATURAL GAS

§ 717a. Definitions

When used in this chapter, unless the context otherwise requires —

(1) "Person" includes an individual or a corporation.

(2) "Corporation" includes any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, receiver or receivers, trustee or trustees of any of the foregoing, but shall not include municipalities as hereinafter defined.

(3) "Municipality" means a city, county, or other political subdivision or agency of a State.

(4) "State" means a State admitted to the Union, the District of Columbia, and any organized Territory of the United States.

(5) "Natural gas" means either natural gas

unmixed, or any mixture of natural and artificial gas.

(6) "Natural-gas company" means a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale.

(7) "Interstate commerce" means commerce between any point in a State and any point outside thereof, or between points within the same State but through any place outside thereof, but only insofar as such commerce takes place within the United States.

(8) "State commission" means the regulatory body of the State or municipality having jurisdiction to regulate rates and charges for the sale of natural gas to consumers within the State or municipality.

(9) "Commission" and "Commissioner" means the Federal Power Commission, and a member thereof, respectively.

(10) "Vehicular natural gas" means natural gas that is ultimately used as a fuel in a self-propelled vehicle.

APPENDIX K — SECTION 4 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717c (1994)

15 U.S.C.A. § 717c

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B—NATURAL GAS

§ 717c. Rates and charges

(a) Just and reasonable rates and charges

All rates and charges made, demanded, or received by any natural-gas company for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges, shall be just and reasonable, and any such rate or charge that is not just and reasonable is declared to be unlawful.

(b) Undue preferences and unreasonable rates and charges prohibited

No natural-gas company shall, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges,

service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Filing of rates and charges with Commission; public inspection of schedules

Under such rules and regulations as the Commission may prescribe, every natural-gas company shall file with the Commission, within such time (not less than sixty days from June 21, 1938) and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection, schedules showing all rates and charges for any transportation or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Changes in rates and charges; notice to Commission

Unless the Commission otherwise orders, no change shall be made by any natural-gas company in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after thirty days' notice to the Commission and to the public. Such notice shall be given

by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the thirty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Authority of Commission to hold hearings concerning new schedule of rates

Whenever any such new schedule is filed the Commission shall have authority, either upon complaint of any State, municipality, State commission or gas distributing company, or upon its own initiative without complaint, at once, and if it so orders, without answer or formal pleading by the natural-gas company, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the natural-gas company affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule

and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of the suspension period, on motion of the natural-gas company making the filing, the proposed change of rate, charge, classification, or service shall go into effect. Where increased rates or charges are thus made effective, the Commission may, by order, require the natural-gas company to furnish a bond, to be approved by the Commission, to refund any amounts ordered by the Commission, to keep accurate accounts in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts were paid, and, upon completion of the hearing and decision, to order such natural-gas company to refund, with interest, the portion of such increased rates or charges by its decision found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon

the natural-gas company, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

APPENDIX L — SECTION 5 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717d (1994)

15 U.S.C.A. § 717d

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B—NATURAL GAS

§ 717d. Fixing rates and charges; determination of cost of production or transportation

(a) Decreases in rates

Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order: Provided, however, That the Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such

natural gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural gas company; but the Commission may order a decrease where existing rates are unjust, unduly discriminatory, preferential, otherwise unlawful, or are not the lowest reasonable rates.

(b) Costs of production and transportation

The Commission upon its own motion, or upon the request of any State commission, whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transportation of natural gas by a natural-gas company in cases where the Commission has no authority to establish a rate governing the transportation or sale of such natural gas.

APPENDIX M — SECTION 7 OF THE NATURAL GAS ACT, 15 U.S.C.A. § 717f (1994)

15 U.S.C.A. § 717f

UNITED STATES CODE ANNOTATED
TITLE 15. COMMERCE AND TRADE
CHAPTER 15B—NATURAL GAS

§ 717f. Construction, extension, or abandonment of facilities

(a) Extension or improvement of facilities on order of court; notice and hearing

Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public, and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company, if the Commission finds that no undue burden will be placed upon such natural-gas company thereby: Provided, That the Commission shall have no authority to compel the enlargement of transportation facilities for such purposes, or to compel such natural-gas

company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers.

(b) Abandonment of facilities or services; approval of Commission

No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

(c) Certificate of public convenience and necessity

(1)(A) No natural-gas company or person which will be a natural-gas company upon completion of any proposed construction or extension shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilities therefor, or acquire or operate any such facilities or extensions thereof, unless there

is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations: Provided, however, That if any such natural-gas company or predecessor in interest was bona fide engaged in transportation or sale of natural gas, subject to the jurisdiction of the Commission, on February 7, 1942, over the route or routes or within the area for which application is made and has so operated since that time, the Commission shall issue such certificate without requiring further proof that public convenience and necessity will be served by such operation, and without further proceedings, if application for such certificate is made to the Commission within ninety days after February 7, 1942. Pending the determination of any such application, the continuance of such operation shall be lawful.

(B) In all other cases the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission; and the application shall be decided in accordance with the procedure provided in subsection (e) of this section and such certificate shall be issued or denied accordingly: Provided, however, that the Commission may issue a

temporary certificate in cases of emergency, to assure maintenance of adequate service or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate, and may by regulation exempt from the requirements of this section temporary acts or operations for which the issuance of a certificate will not be required in the public interest.

(2) The Commission may issue a certificate of public convenience and necessity to a natural-gas company for the transportation in interstate commerce of natural gas used by any person for one or more high-priority uses, as defined, by rule, by the Commission, in the case of —

(A) natural gas sold by the producer to such person; and

(B) natural gas produced by such person.

(d) Application for certificate of public convenience and necessity Application for certificates shall be made in writing to the Commission, be verified under oath, and shall be in such form, contain such information, and notice thereof shall be served upon such interested parties and in such manner as the Commission shall, by regulation, require.

(e) Granting of certificate of public convenience and necessity

Except in the cases governed by the provisos contained in subsection (c) (1) of this section, a certificate shall be issued to any qualified applicant therefor, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of this chapter and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied. The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

(f) Determination of service area; jurisdiction of transportation to ultimate consumers

(1) The Commission, after a hearing had

upon its own motion or upon application, may determine the service area to which each authorization under this section is to be limited. Within such service area as determined by the Commission a natural-gas company may enlarge or extend its facilities for the purpose of supplying increased market demands in such service area without further authorization; and (2) If the Commission has determined a service area pursuant to this subsection, transportation to ultimate consumers in such service area by the holder of such service area determination, even if across State lines, shall be subject to the exclusive jurisdiction of the State commission in the State in which the gas is consumed. This section shall not apply to the transportation of natural gas to another natural gas company.

(g) Certificate of public convenience and necessity for service of area already being served

Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural-gas company.

(h) Right of eminent domain for construction of pipelines, etc.

Appendix M

When any holder of a certificate of public convenience and necessity cannot acquire by contract, or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas, and the necessary land or other property, in addition to right-of-way, for the location of compressor stations, pressure apparatus, or other stations or equipment necessary to the proper operation of such pipe line or pipe lines, it may acquire the same by the exercise of the right of eminent domain in the district court of the United States for the district in which such property may be located, or in the State courts. The practice and procedure in any action or proceeding for that purpose in the district court of the United States shall conform as nearly as may be with the practice and procedure in similar action or proceeding in the courts of the State where the property is situated:

Provided, That the United States district courts shall only have jurisdiction of cases when the amount claimed by the owner of the property to be condemned exceeds $3,000.